2020 CALIFORNIA ELECTRIC AND GAS UTILITY COSTS REPORT

AB 67 Annual Report to the Governor and Legislature

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California Public Utilities Commission

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Executive Summary

The California Public Utilities Commission (CPUC) issues the Assembly Bill (AB) 67 Annual Report (referred to as the 2020 California Electric and Gas Utility Costs Report) pursuant to California Public Utilities Code Section 913, which requires the CPUC to publish the costs to ratepayers of all utility programs and activities currently recovered in retail rates.[1]

The 2020 California Electric and Gas Utility Costs Report, published in 2021, provides a detailed narrative and transparency into factors driving electric and gas rates for 2020 activities.

Key electric highlights from this report include:

- Compared to 2019, the 2020 CPUC-authorized annual revenue requirement for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) increased by 5.2 percent, 9.0 percent, and 0.2 percent, respectively.
    - Compared to 2019, the 2020 generation costs increased for PG&E by 5.1 percent, and decreased for SCE and SDG&E by 6.8 percent and 9.4 percent, respectively. During the same time period, distribution costs increased for PG&E, SCE, and SDG&E by 6.5 percent, 34.2 percent, and 12.3 percent, respectively. Electric generation and distribution are the largest components of electric rates, and collectively account for approximately 66 percent of the utilities' electric rates.
- Compared to 2019, the 2020 transmission costs increased for PG&E by 12.0 percent and decreased for SDG&E and SCE by 11.9 percent and 6.7 percent, respectively.
- In Federal Energy Regulatory Commission (FERC) proceedings for transmission owner (TO) rate cases from 2008 to 2020, the CPUC has successfully negotiated a reduction to the transmission revenue requirements resulting in a cumulative savings of approximately $2.24 billion for California ratepayers.
- In 2020, the electric California investor-owned utilities collectively included approximately $149 million in greenhouse gas cap and trade costs in rates but provided ratepayers approximately $771 million in rebates from their proceeds from selling their carbon allowance.

[1] Section 913 reporting requirements apply to electrical corporations with at least 1,000,000 retail customers in California and gas corporations with at least 500,000 retail customers in California.

- In 2020, Demand-Side Management program[2] costs, when combined, accounted for three percent of the total electric revenue requirement for the four large IOUs in California (PG&E, SCE, SDG&E, and Southern California Gas Company (SoCalGas)).
- Regulatory fees[3] in 2020 totaled approximately $592 million and accounted for roughly five percent of the annual revenue requirement for the electric IOUs (PG&E, SCE, and SDG&E).
- Increases in total system average rates generally tracked inflation from 2005 through 2015. SDG&E's average rates have been above the Consumer Price Index since 2009. Since 2015, SCE's average rates have been below the inflation rate while PG&E's average rates have been above and below the inflation rate.

Key gas highlights from this report include:

- Compared to 2019, the 2020 total natural gas utility costs decreased by 0.3 percent. The decrease in natural gas resulted from a substantial drop in core[4] procurement costs, balanced by an increase in transportation costs.

[2] Demand-Side Management programs include programs such as Energy Efficiency, Energy Savings Assistance, California Alternative Rates for Energy (administrative costs only), Self-Generation Incentive Program, Demand Response, and Electric Program investment Charge.

[3] Regulatory fees include a variety of charges levied by federal, state, and local governments.

[4] The typical natural gas utility customers in California are residential and small commercial customers, referred to as "core" customers.

I. Introduction

Enacted as AB 67 in 2005, California Public Utilities Code 913 requires the CPUC to prepare a written report on the costs of programs and activities conducted by the four major electric and gas companies regulated by the CPUC. This legislation was enacted in part to determine the effect of various legislative and administrative mandates, and to provide more transparency into factors driving electric and gas rates.

The report is to be submitted to the Governor and the Legislature by April 1st of each year and is required to include the following:

1. Each program mandated by statute and its annual cost to ratepayers.
2. Each program mandated by the CPUC and its annual cost to ratepayers.
3. Energy purchase contract costs and bond-related costs incurred pursuant to Division 27 of the Water Code (commonly known as Department of Water Resources (DWR) related costs).
4. All other aggregated categories of costs currently recovered in retail rates as determined by the CPUC.

This 2020 California Electric and Gas Utility Costs Report is submitted by the CPUC to fulfill these statutory requirements.

Background

The cost structures and the rate-setting process for California's utilities are inherently complex and can be difficult to track over time. To help create more transparency in the rate-setting process, the California Legislature passed AB 67 in 2005. AB 67 establishes an annual reporting requirement to identify the costs to ratepayers of all utility programs and activities currently recovered in retail rates. As in previous years, this report provides a detailed narrative of various energy policies in California, along with a breakdown of the underlying costs that drive electric and gas rates, including charts and tables showing how these costs and rates have varied since 2010.

The report presents an analysis of the CPUC-authorized revenue requirements for the four major California investor-owned utilities (IOUs or utilities): PG&E, SCE, SDG&E, and SoCalGas. Using sales forecasts, rates are set to collect these authorized revenue requirements. For certain utility programs, discrepancies between authorized revenue requirements and actual revenues and expenses are captured through balancing account mechanisms, which true-up the actual revenue to the authorized revenue requirement in the following year. This mitigates the risk of the utilities collecting more than or less than their authorized revenue requirements, particularly if sales are lower than forecast due to conservation and efficiency programs.

Overview

Electric Utility Costs

- **Compared to 2019, the CPUC-authorized annual revenue requirements[5] for PG&E, SCE, and SDG&E increased by 5.2 percent, 9.0 percent, and 0.2 percent, respectively.** The 2020 revenue requirement for the three electric utilities are shown in **Table 1.1**. The total company revenue requirement (including transmission)[6] for the electric utilities in 2020 is as follows: PG&E $14.1 billion, SCE $12 billion, and SDG&E $4.1 billion for a total of $30.2 billion.

Table 1.1: Electric Utility Revenue Requirement Comparison ($000)[7]

Utility	2020 CPUC	2019 CPUC	Difference ($000)	Difference %	2020 Transmission	2020 Total Company
PG&E	11,624,239	11,054,893	569,346	5.2	2,469,714	14,093,952
SCE	11,059,550	10,150,335	909,215	9.0	949,095	12,008,645
SDG&E	3,582,913	3,576,792	6,121	0.2	559,089	4,142,002
Total	**26,266,702**	**24,782,020**	**1,484,682**	**6.0**	**3,977,898**	**30,244,599**

Much of the increase in PG&E's, SCE's, and SDG&E's revenue requirements are due to amortization of balances in various balancing and memorandum accounts that were authorized in various CPUC Decisions and included in the utilities' general rate cases (GRC).[8]

- **Power procurement costs increased for PG&E, and decreased for SCE and SDG&E during 2020.** Power procurement costs include the costs of generating and purchasing electricity as well as capital costs related to those items. **Table 1.2** shows the 2020 revenue requirement for the three electric utilities associated with generating electricity.

[5] All references to revenue requirements are to the CPUC-authorized annual revenue requirement and are in current dollars (not adjusted for inflation) unless otherwise indicated.

[6] The Federal Energy Regulatory Commission has jurisdiction over transmission-related revenue requirements.

[7] PG&E Advice Letter 5661-E-A, SCE Advice Letter 4172-E, and SDG&E Advice Letter 3452-E-B, effective 5/1/2020, 4/13/2020, and 1/1/2020.

[8] See Chapter II for a discussion on general rate cases revenue requirements.

Table 1.2: Electric Generation Revenue Requirement Comparison ($000)

Utility	2020	2019	Difference	
			$000	%
PG&E	5,513,712	5,247,515	266,197	5.1
SCE	5,508,750	5,910,443	(401,694)	(6.8)
SDG&E	1,523,136	1,680,674	(157,538)	(9.4)
Total	**12,545,597**	**12,838,633**	**(293,035)**	**(2.3)**

Much of the increase in PG&E's generation revenue requirement is due to the amortization of the undercollected balance of Power Charge Indifference Adjustment costs in the Portfolio Allocation Balancing Account that was authorized in CPUC's Decision 20-02-047. Most of SCE's decrease in generation revenue requirement is due to lower procurement costs resulting from the migration to Customer Choice Aggregators (CCAs). SDG&E's decrease is due to lower procurement costs. For additional analysis, see Chapter III.

Since 2016, the IOUs have seen a growing percentage of their load move to service from CCAs. In 2020, 29 percent of total system load was served by CCAs.

- **Electric distribution costs increased for PG&E, SCE, and SDG&E.** Distribution costs include the costs of providing service below a certain voltage (60 kilovolt (kV), 200 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are regulated by the CPUC. **Table 1.3** shows the 2020 revenue requirement for the three electric utilities associated with distribution of energy through the electric grid.

Table 1.3: Electric Distribution Revenue Requirement Comparison ($000)

Utility	2020	2019	Difference	
			$000	%
PG&E	5,273,802	4,951,529	322,273	6.5
SCE	4,939,144	3,679,985	1,259,159	34.2
SDG&E	1,694,297	1,508,309	185,988	12.3
Total	**11,907,242**	**10,139,822**	**1,767,420**	**17.4**

PG&E's increase can be attributed to the amortizations of the balance in the Hazardous Substance Mechanism. SCE's distribution revenue requirement was increased mainly by higher customer services costs and higher regulatory obligation costs. SDG&E's increase can be attributed to the 2020 attrition year adjustment as authorized in its last general rate case. For additional analysis, see Chapter III.

- **Compared to 2019, electric transmission costs increased for PG&E and decreased for SCE and SDG&E.** Transmission costs include the costs of providing service above a certain voltage (60 kV, 200 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are part of the high voltage electric grid controlled by the California Independent System Operator (CAISO) and regulated by the FERC. **Table 1.4** shows the 2020 transmission costs for the three electric utilities associated with distribution of energy through the electric grid.

Table 1.4: Electric Transmission Costs Comparison ($000)

Utility	2020	2019	Difference	
			$000	%
PG&E	2,469,714	2,206,039	263,675	12.0
SCE	949,095	1,016,889	(67,795)	(6.7)
SDG&E	559,089	634,909	(75,820)	(11.9)
Total	**3,977,898**	**3,857,837**	**120,060**	**3.1**

PG&E's overall transmission cost increase related to an increase in the rates it was allowed to collect as part of its still pending rate case at FERC[9]. SDG&E's decrease is related to: 1) a decrease in the forecast plant additions for 2020, 2) an adjustment related to SDG&E's calculation of its Accumulated Deferred Income Taxes, and 3) True-Up adjustments between FERC transmission rate case cycles.[10] SCE's reduction in transmission costs relates to the successful negotiation of a new rate formula which decreases the revenue requirement authorized by FERC.[11] For additional analysis, see Chapter III.

- **Energy Efficiency and Low-Income program costs increased for SCE, and decreased for PG&E and SDG&E, since 2019.** These Public Purpose Programs (PPPs) involve energy efficiency improvements for all customers and rate discounts for low-income customers. **Table 1.5** shows the 2020 revenue requirement for the three electric utilities associated with PPPs.

[9] As a result of the settlement in its TO20 rate case, which was filed at FERC on October 15, 2020, PG&E's ratepayers will see refunds resulting from a reduction in PG&E's 2019 rates by over $150 million and a reduction in the 2020 rates by between $250 and $300 million.

[10] SDG&E's TO5 Cycle 2 Formula Rate Filing, TO5-Cycle 2, Transmittal Letter, December 2, 2019.

[11] Settled Rate Case TO2019A, FERC Docket ER19-1553. See the discussion in Chapter III on transmission revenue requirements for more information.

Table 1.5: Electric PPP Revenue Requirement Comparison ($000)

Utility	2020	2019	Difference	
			$000	%
PG&E	315,820	446,150	(130,330)	(29.2)
SCE	223,435	220,701	2,735	1.2
SDG&E	297,507	311,011	(13,504)	(4.3)
Total	**836,762**	**977,862**	**(141,099)**	**(14.4)**

Much of the change in the PPP revenue requirement is due to the revenue adjustment mechanisms for the Electric Program Investment Charge (EPIC) and other PPPs, which collect or refund the difference between the authorized revenue requirement and recorded revenue. PG&E and SDG&E over-collected these funds in 2019 which led to a reduction in collections in 2020.

- **Bonds and Regulatory Fees (including nuclear decommissioning revenue requirements) decreased for SDG&E, and increased for PG&E and SCE during 2020.** During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. Fees include a variety of charges levied by federal, state, and local governments. Fees are included as specific components of other revenue requirements, except for nuclear decommissioning costs, which are recovered by the Nuclear Decommissioning Adjustment Mechanism (NDAM). **Table 1.6** shows the 2020 revenue requirements for the three electric utilities associated with bonds and nuclear decommissioning activities.

Table 1.6: Bonds and Fees Revenue Requirement Comparison ($000)

Utility	2020	2019	Difference	
			$000	%
PG&E	520,905	409,699	111,206	27.1
SCE	388,221	370,695	17,526	4.7
SDG&E	67,974	76,798	(8,825)	(11.5)
Total	**977,100**	**857,192**	**119,907**	**14.0**

During 2020, much of the variation in the revenue requirements for bonds and assorted fees was driven by DWR bond charges. For additional analysis, see Chapter VI.

- **The revenue requirement for PG&E, SCE, and SDG&E increased in 2020 due to adjustments for amortizations of balances in balancing and/or memorandum accounts. Table 1.7** shows the effect of these adjustments on the revenue requirements for the electric utilities.

Table 1.7: Adjustments to the 2020 Revenue Requirement ($000)

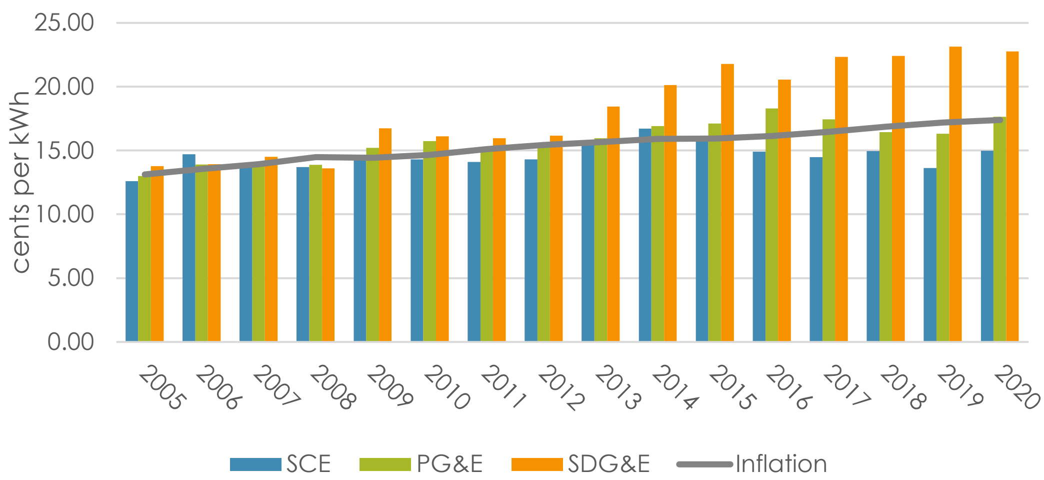
Utility	Forecasted 2020 Costs	Amortization Adjustments	Authorized 2020 Revenue Requirement	Difference %
PG&E	10,692,808	931,430	11,624,239	8.7%
SCE	10,843,945	215,605	11,059,550	2.0%
SDG&E	3,117,558	465,355	3,582,913	14.9%
Total	**24,654,312**	**1,612,390**	**26,266,702**	**6.5%**

Utilities add amortizations of balancing and/or memorandum accounts to the annual revenue requirement to recover costs of prior years and set rates incorporating this adjustment. The information in this report refers to the adjusted annual revenue requirement to show the annual cost to ratepayers.

- **Increases in System Average Rates generally tracked inflation from 2005 through 2015, except for SDG&E. SDG&E's average rates have been above the Consumer Price Index (CPI) since 2009. Since 2015, SCE's average rates have been below the inflation rate while PG&E's average rates have been above and below the inflation rate (Figure 1.1).** From 2016 to 2020, system average rates across the three electric IOUs have increased at an annual average of approximately 0.8 percent (**Table 1.8**), which is below the average annual inflation rate of 1.8 percent over the same time period, even though SCE and SDG&E shows an increase this year. In 2020, SCE's system average rate was 14.97 cents per kilowatt hour (¢/kWh), PG&E's was 17.65 ¢/kWh, and SDG&E's was 22.75 ¢/kWh. To show the effect of inflation from 2005 – 2020, the average of all three utilities' system average rate in 2005, adjusted for inflation to 2020 nominal dollars, is 17.39 ¢/kWh. The average of all three utilities' system average rate for 2020 is 18.5 ¢/kWh, which suggests that the cost of electricity to the ratepayer generally increased by 1.07 ¢/kWh since 2005 when excluding the effects of inflation. The average rate of the utilities in 2005 adjusted for inflation to arrive at a 2020 CPI-adjusted average rate is 17.39 ¢/kWh.[12]

[12] PG&E Advice Letter 5661-E-A, SCE Advice Letter 4172-E, and SDG&E Advice Letter 3452-E-B, effective 5/1/2020, 4/13/2020, and 1/1/2020, respectively.

Figure 1.1: Trends in Electric Total System Average Rates (2005-2020)[13]



Annual Inflation Rate (2010-2020)[14]											
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Average (2016-20)
1.6%	3.2%	2.1%	1.5%	1.6%	0.1%	1.3%	2.1%	2.4%	1.8%	1.2%	**1.8%**

Table 1.8: Annual Change in Electric Total System Average Rates (2016-2020)

Utility	2016	2017		2018		2019		2020		Average
	Rate	Rate	% Change	Rate	% Change	Rate	% Change	Rate	% Change	% Change
SCE	14.90	14.48	(2.8)	14.96	3.3	13.62	(8.9)	14.97	9.9	0.4
PG&E	18.28	17.42	(4.7)	16.43	(5.7)	16.30	(0.8)	17.65	8.3	(0.7)
SDG&E	20.54	22.32	8.7	22.40	0.3	23.13	3.3	22.75	(1.7)	2.7

- **For SDG&E, system average rates have generally trended above inflation since 2009.** All three utilities have experienced declines in kWh sales, which also lead to increased system average rates when the revenue requirement remains flat or rises. The increase in average rates for PG&E in 2020 result from recent outcomes in its GRC. SCE's increase in system average rates for 2020 is due to an increase in distribution costs. SDG&E's decreased system average rate for 2020 is due to a decrease in transmission costs.

[13] Total System Average Rates reflect total authorized revenue requirement and total forecasted sales for both bundled and unbundled customers.

[14] Source: Bureau of Labor Statistics, CPI-All Urban Consumers.

- **Electric generation and distribution are the largest components of electric rates.** As shown in **Figure 1.2** and **Table 1.9**, utility-owned generation and purchased power sources, plus distribution, collectively account for approximately 80 percent of the utilities' electric rates.

Figure 1.2: 2020 Electric Rate Components

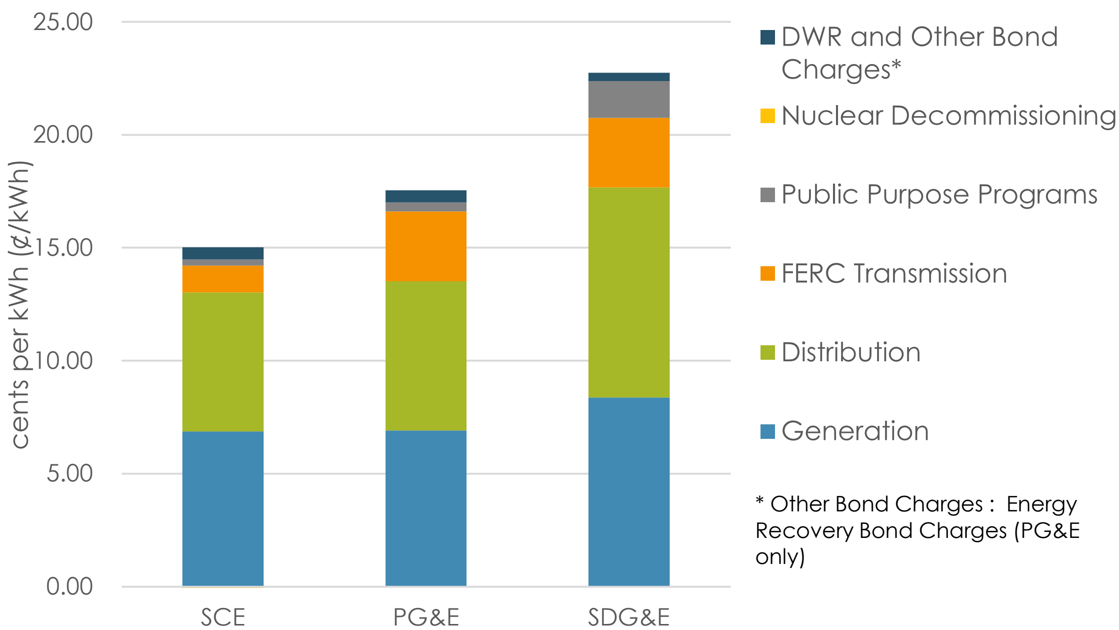


Table 1.9: 2020 Electric Rate Component Values (¢/kWh)

Rate Component	SCE[15]	PG&E	SDG&E
Generation	6.87	6.90	8.36
Distribution	6.16	6.60	9.30
FERC Transmission	1.18	3.09	3.07
Public Purpose Program	0.28	0.40	1.63
Nuclear Decommissioning	(0.05)	0.11	0.01
DWR and Other Bond Charges	0.53	0.54	0.37
Total	**14.97**	**17.65**	**22.75**

[15] The negative value for nuclear decommissioning rate component for SCE is associated with the overcollection of revenue. These overcollections were returned to ratepayers in 2020.

<u>Gas Utility Costs</u>

- **For 2020, total natural gas utility costs decreased by 0.3 percent from 2019 compared to the 12.8 percent increase for 2018 to 2019 and the 2.7 percent decrease from 2017 to 2018**. While the overall decrease in 2020 is minor, it resulted from a substantial drop in core procurement costs, balanced by an increase of the same magnitude in transportation costs. Core procurement costs decreased due to relatively flat gas commodity prices, reduced volatility and a milder 2019-20 winter. Transportation costs increased because of increased expenditure on distribution systems and also an increase in balancing account balances. Please see Chapter VII for a discussion of gas utility costs.

The remainder of this report provides a breakdown of the various electric and natural gas revenue requirement components and identifies the sources of the greatest increases in costs. Chapters II through VI address electric revenue requirements and Chapter VII addresses natural gas revenue requirements. In addition to the detailed summary tables provided throughout the text, Appendix A and Appendix B provide summaries of the IOU authorized revenue requirements organized by the rate components typically shown on customer bills.

II. Determining Revenue Requirements

Due to the increasingly varied nature of utility costs and the multitude of energy policy programs, the determination of the funds needed for utility service and the rate-setting process at the CPUC have grown more complex over time. The following venues are used to determine the revenues that the utilities are authorized to collect through rates:

1. **General Rate Cases (GRCs):** GRCs occurred on a three-year cycle at the CPUC, and are transitioning to a four-year cycle based on Decision (D.) 20-01-002. In GRCs, the CPUC evaluates the regulated operations of the IOUs and determines the reasonableness of IOU requests for changes in revenue needed to fund utility service. For PG&E, SCE, and SDG&E, the GRCs are divided into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect (also called the "revenue requirement"), while Phase II determines the share of the utility's total cost each customer class is responsible and the rate schedules for each class.
2. **Transmission rate cases at the Federal Energy Regulatory Commission (FERC):** The CPUC is required to allow recovery of all FERC-authorized costs. Because transmission rates are subject to oversight by FERC, the transmission revenue requirements of the various utilities that participate in the CAISO are determined in FERC proceedings, called Transmission Owner (TO) rate cases.
3. **Energy Resource Recovery Account (ERRA) proceedings**: The CPUC annually reviews each utility's fuel and power purchase forecast and, to the extent deemed reasonable, passes through those costs without any profit or mark-up for the utility. Some public purpose charges are also authorized here.
4. **Program Budget allocations**: Specific program area proceedings in which program budgets are determined.

The utilities earn a rate of return (authorized profit from rate base) on utility-owned and capitalized assets and equipment. For many cost categories, such as purchased power and fuel, there is no rate of return or profit – the utilities are only reimbursed for these costs from customers as "pass-through" costs.

Categorization of Utility Costs

Utility costs or revenue requirements fall into three major categories: generation, distribution, and transmission. While this basic categorization of costs reflects major areas of utility operations or business units, it is also used to determine what portions of utility costs should be paid by different types of customers. For instance, some customers do not receive full or bundled service from the utility and may generate their own electricity on site or buy electricity from a non-utility source (e.g., an Electric Service Provider (ESP), or a Community Choice Aggregator (CCA)). Customers who receive electricity from a CCA or ESP do not typically pay generation costs but do pay transmission and distribution costs. However, these customers are also required to pay non-bypassable charges for generation procured on their behalf before they departed from bundled service. Additionally, some larger customers receive service at transmission voltage levels and are not charged for use of the utility distribution system. **Table 2.1** offers a breakdown of the major components of the electric IOUs' 2020 revenue requirements.

Table 2.1: 2020 Electric IOU Authorized Revenue Requirements ($000)

Revenue Component	SCE	PG&E	SDG&E
Generation / Energy Procurement	5,508,750	5,513,712	1,523,136
Purchased Power	4,676,086	2,932,707	1,120,750
Utility Owned Generation	85,370	339,920	273,414
General Rate Case	735,315	2,238,948	183,153
Other Regulatory	11,978	2,137	(54,182)
Distribution	4,777,874	4,988,079	1,517,842
Transmission	949,095	2,469,714	559,089
Public Purpose Programs	286,496	161,861	470,616
Bonds and Fees	486,431	960,587	71,319
Total 2019 Revenue Requirement	**12,008,645**	**14,093,952**	**4,142,002**

Rate Base

The rate base is the book value, after depreciation, of the generation, distribution, and transmission infrastructure owned and operated by the utility for the provision of electric service. Utilities earn a regulated Rate of Return (ROR) on rate base based on their capital structure, debt interest rates, and authorized return on equity (ROE). This ROR is the main source of profit for regulated utilities. Other things being equal, a larger rate base results in a higher net profit for the utilities.

Depreciation causes the utilities' rate base for existing assets to decline over the useful life of the asset, while building new plants or making capital improvements to existing plants causes their rate base to increase. Changes in rate base also result in changes in the depreciation expense allowance utilities are authorized to collect. As shown in **Figure 2.1** below, the result of these competing effects has historically been a net increase in rate base. **Figure 2.1** indicates that between 2010 and 2020, the utilities' rate base doubled in size from $36.3 billion to $72.9 billion, or a 101 percent increase in nominal dollars over the past decade, triggering corresponding increases in GRC revenue requirements.[16]

[16] When adjusted for inflation, the 2010 rate base equals $43.2 billion. Therefore, an inflation adjusted comparison of rate base from 2010 to 2020, the rate base increased in size from $43.2 billion (adjusted for inflation from $36.3 billion) to $72.9 billion, which yields a 69 percent increase.

Figure 2.1: Trends in Electric Utility Rate Base

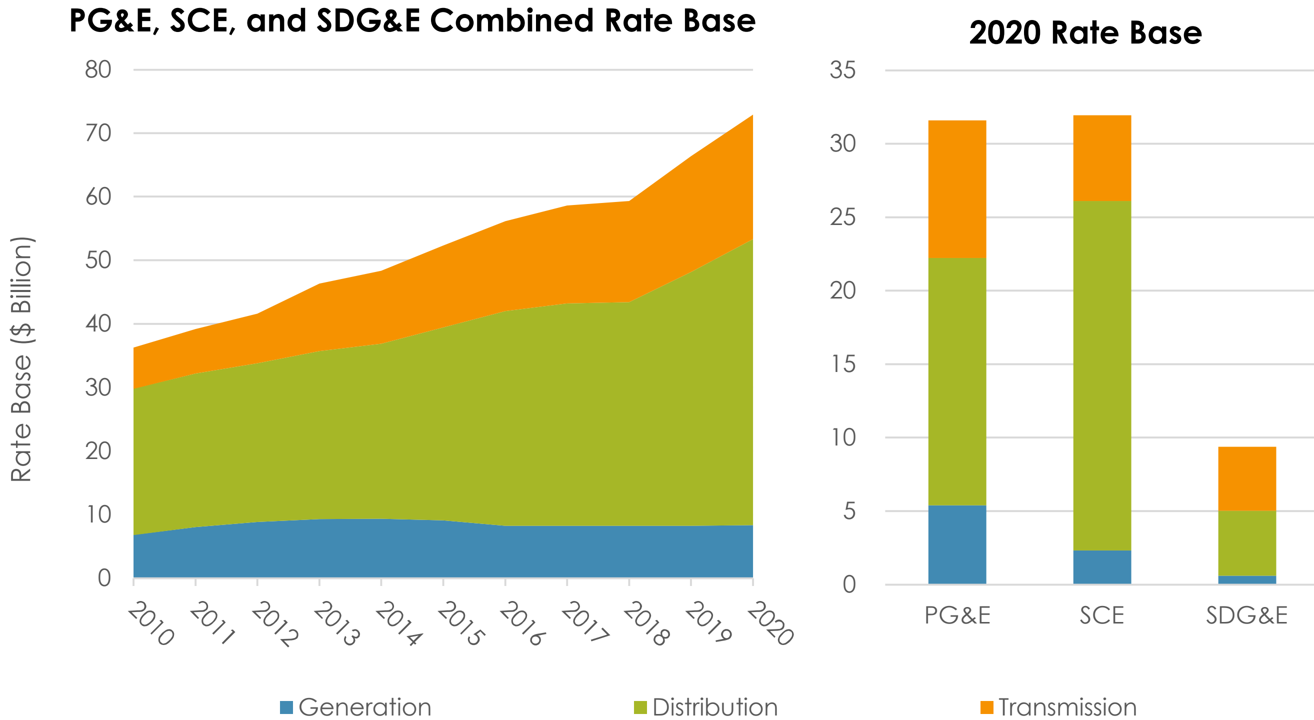


Table 2.2 shows the contributions of generation, transmission, and distribution components to the 2020 rate base.

Table 2.2: 2020 Utility Rate Base Components ($000)

Category	PG&E	SCE	SDG&E	Total
Generation	5,400,524	2,322,510	610,292	
Distribution	16,817,603	23,781,514	4,412,803	
Transmission	9,377,870	5,829,102	4,359,546	
Total All IOUs	**31,595,997**	**31,933,126**	**9,382,641**	**72,911,764**

III. General Rate Case Revenue Requirements

Costs that utilities can forecast with reasonable accuracy are examined and approved by the CPUC in general rate case (GRC) proceedings. In January 2020, the major utilities were directed by the CPUC to take procedural steps to transition from the current three-year GRC cycle to a four-year GRC cycle.[17] In these GRC proceedings, the CPUC sets a pre-specified revenue requirement for the first year in the cycle, or "test year," with formulaic adjustments for the subsequent "attrition years" until the next GRC cycle commences.

The utilities' authorized revenue requirements typically remain unchanged even if the utilities spend more or less than authorized by the CPUC. The exception to this occurs in operations covered by balancing and/or memorandum accounts which can adjust the authorized revenue requirement based on actual spending upon CPUC approval.

Approximately 61 percent of the utilities' electric revenue requirements are set in GRCs at the CPUC and the FERC (FERC sets the revenue requirement for transmission assets), while the remaining 39 percent consists of pass-through of the costs of power procurement, DWR bond charges, nuclear decommissioning trusts, Public Purpose Programs, fees, and regulatory expenses approved by the CPUC.

GRC revenue requirements generally break down into the Distribution, Utility Owned Generation (UOG), and Transmission categories, and each is comprised of the following major cost elements: O&M, Depreciation, Return on Rate Base, and Taxes. **Table 3.1** below summarizes the total CPUC-jurisdictional GRC revenue requirements as broken down into these cost categories for the three electric utilities, followed by detailed descriptions of each.

[17] The CPUC adopted a revised application filing schedule to be applied to all future GRCs, effective June 30, 2020. Because the utilities were in various stages of their current GRCs, they were directed to take procedural steps to implement the transition to the four-year GRC cycle. Source: CPUC Decision 20-01-002, January 22, 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF.

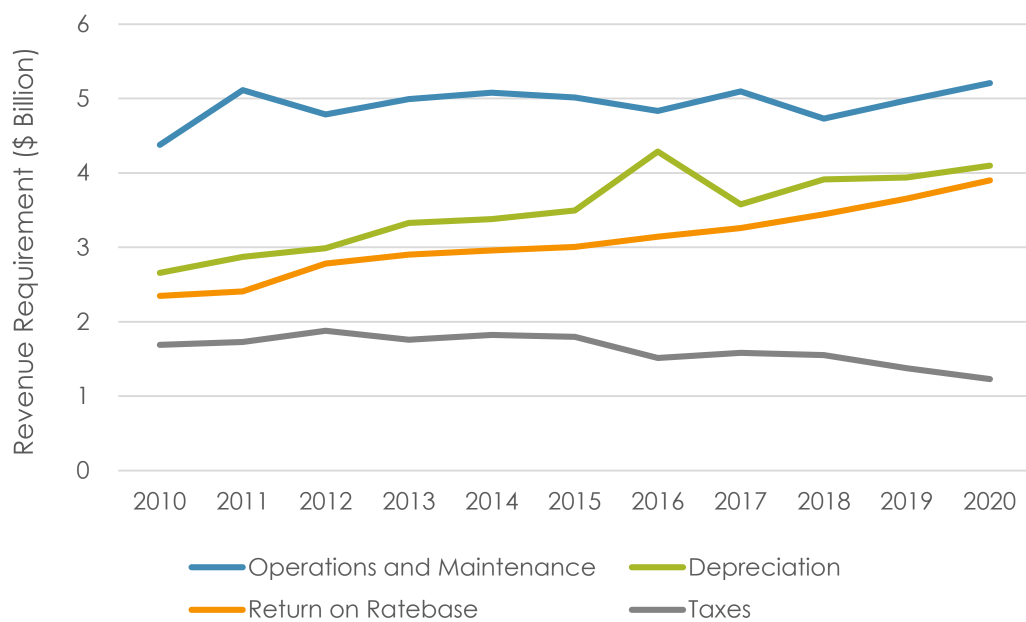
Table 3.1: 2020 General Rate Case Revenue Requirements ($000)[18]

	PG&E	SCE	SDG&E
Operation and Maintenance	3,278,938	1,186,028	743,870
Depreciation	1,917,991	1,759,130	420,271
Return on Rate Base	1,544,249	2,003,491	355,347
Taxes	485,848	564,540	181,508
Total	**7,227,027**	**5,513,189**	**1,700,995**

(Excludes FERC determined transmission revenue requirements)

Figure 3.1 below shows a ten-year trend of the costs for O&M, Depreciation, Return on Rate Base, and Taxes for the utilities.

Figure 3.1: Trends in General Rate Case Revenue Requirement[19]



- **<u>Operations and Maintenance (O&M)</u>:** These costs include all labor and non-labor expenses for a utility's operation and maintenance of its generation plants and distribution system. While the utilities are required to maintain their systems in accordance with safety and reliability standards and industry best practices, the CPUC does not typically dictate how the utilities spend O&M funds. Depending on how the utilities manage various projects, they may spend more or less than the CPUC authorized O&M budget.

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[18] Amounts shown include revenues adopted by the CPUC in the utilities' GRCs and additional revenues approved by the CPUC for inclusion in base revenues after the GRC decisions were issued.

[19] Values shown are for Distribution and Generation Revenue Requirement.

To better assess utility spending on ensuring the safe operation of their systems, the CPUC adopted a framework for incorporating risk-based decision-making into GRCs in 2014. This risk-based decision-making framework involves two key components: the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, and a Risk Assessment Mitigation Phase (RAMP) for each large energy utility one year in advance of its GRC proceeding.

In 2015, the S-MAP applications of the major electric and gas utilities were consolidated, and the utilities and parties discussed the methods by which to assess the risks in their operations. In 2020, a second S-MAP was opened to enhance the RAMP process. Each utility's RAMP proceeding utilizes the reporting format developed in the S-MAP proceeding and describes how the utility plans to assess and mitigate its risks. SDG&E and SoCalGas were the first utilities to initiate the RAMP, in October 2016, followed by PG&E in November 2017, and SCE in November 2018. A second RAMP opened for SDG&E and SoCalGas in November 2019 was subsequently closed by CPUC D.20-09-004 to accommodate the transition to a four-year GRC cycle.[20] In June 2020, PG&E submitted its 2020 RAMP. In the general rate cases, the CPUC undertakes a thorough review of O&M costs, separately, for generation and distribution related facilities, and for general plant. Beginning in Test Year 2019, the CPUC incorporated RAMP findings into the utilities' GRC decisions.

- **Depreciation:** Capital investments in facilities and assets are initially financed by the utilities' own funding sources and are returned to the utilities with ratepayer funding in the form of a depreciation allowance. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.

- **Rate of Return on Rate Base:** Because the utilities provide the upfront financing for all capitalized expenditures, the CPUC authorizes a rate of return (ROR) on the invested capital. The ROR is the weighted average cost of debt and shareholder equity, and the CPUC allows the opportunity to earn a fair and reasonable return sufficient to allow the utilities to obtain financing. Formerly determined in each utility's GRC, the ROR is now determined in a separate cost of capital proceeding for the major IOUs. The utilities' actual ROR may be more, or less, than what is authorized by the CPUC, depending on how well the utilities manage their operations and costs. In most instances, if the utilities keep costs below their authorized revenues, actual ROR will exceed the authorized level. GRC ratemaking is aimed at providing the utilities with an incentive to stay within approved, pre-specified budgets. Under this ratemaking treatment, utility profits decline if spending is higher than the GRC authorized revenue requirement, and vice versa.

In addition to the authorized ROR, the CPUC has instituted incentive programs, such as the Efficiency Savings and Performance Incentive mechanism, whereby utility shareholders are eligible to receive payments for achieving good energy savings performance. The utilities do not earn a return on purchased power and fuel

[20] CPUC directed SDG&E and SoCal Gas to submit a new RAMP application in mid-2021.

expenditures, which, as noted elsewhere in this report, are pass-through costs reviewed in Energy Resource Recovery Account (ERRA) proceedings.

The CPUC also requires the utility to track some costs in "one-way balancing accounts." For expense categories tracked in one-way balancing accounts, if the utility underspends, then the utility returns the funds to ratepayers. If a utility overspends, in a one-way balancing account, the utility has to absorb the costs in profits. One-way balancing accounts are occasionally used for spending related to safety such that the utility does not profit from underspending in those areas.[21]

Distribution Revenue Requirement

Since 2010, the total distribution revenue requirement has increased, from $8.18 billion to $11.28 billion (**Figure 3.2**).[22] Over the same time period, depreciation expenses have experienced the greatest increase, with an approximate 2.9 percent average annual growth rate.[23] The increases in distribution costs are primarily due to capital additions and ongoing infrastructure modernization and improvements to the distribution system, which have increased rate base, as discussed on page 13.

[21] In the past, utilities were authorized costs for safety-related programs without the use of a balancing account. If a utility spent less, then it could retain the net revenues, including profits, for those programs. To prevent the utilities from profiting from safety-related programs, the CPUC adopted balancing accounts for these programs. One ratemaking mechanism is to cap safety spending in a "one-way" balancing account to avoid ratepayers paying costs above authorized and to have the utilities refund any net revenues to ratepayers instead of retaining them. More often of late, the CPUC uses "two-way" balancing accounts for safety costs to allow utilities to recover much needed expenditures from ratepayers for safety spending such as wildfire prevention. Utilities are prevented from profiting off this system, and if a utility spends more than authorized, it may seek to recover its additional spending as directed when the account is established.

[22] When adjusted for inflation, the 2010 total distribution revenue requirement corresponds to $9.7 billion, resulting in an approximately 16 percent increase in 2020 dollars.

[23] Adjusted for inflation.

Figure 3.2: Trends in Distribution Revenue Requirement

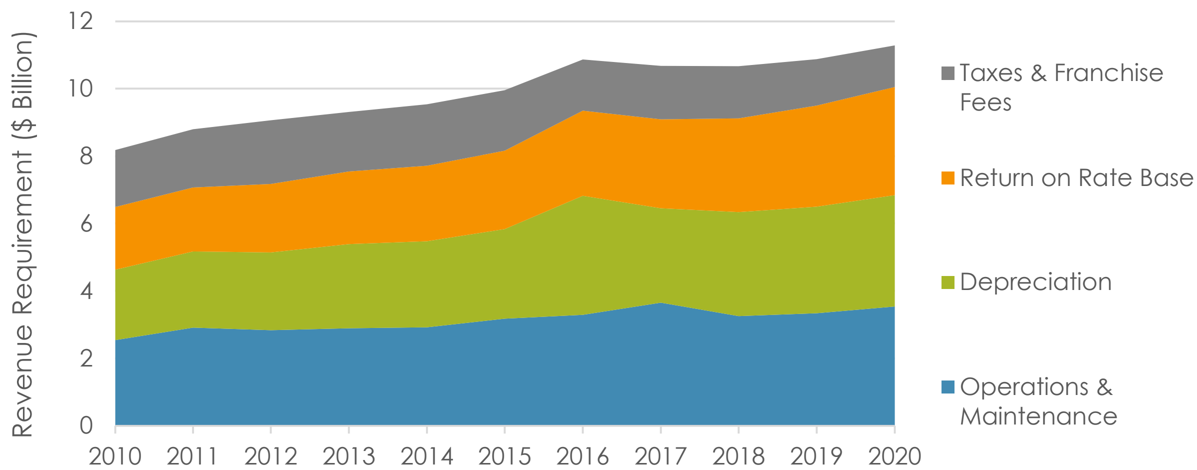


Table 3.2 below shows the contributions of distribution components to the 2020 revenue requirement.

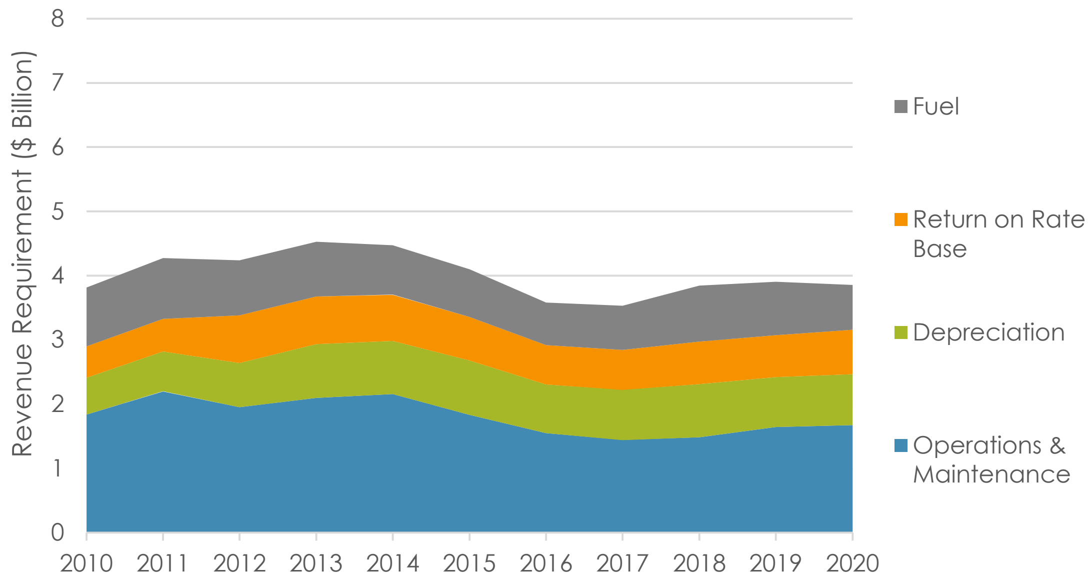
Table 3.2: 2020 Distribution Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	2,022,392	856,212	656,372
Depreciation	1,364,495	1,570,925	370,070
Return on Rate Base	1,115,344	1,786,197	309,893
Taxes and Franchise Fees	485,848	564,540	181,508
Total	**4,988,079**	**4,777,874**	**1,517,843**

Utility Owned Generation Revenue Requirements

The revenue requirement for utility-owned (or retained) generation (UOG) includes O&M costs, depreciation, and return on rate base related to these facilities. As older generating plants depreciate, costs of owning those plants decrease over time, even though costs of operating them may increase. As new plants are built by the utilities or capital improvements are made to existing facilities, the capital costs of the new plants typically exceed the capital costs of the old plants they replace. As a result, the generation rate base tends to increase over time as shown in **Figure 3.3**.

Figure 3.3: Trends in Generation Revenue Requirement



*Fuel costs are not included in the GRC but are reflected in generation revenue requirements

Spikes in UOG revenue requirement in 2011 and 2013 were mainly the result of amortization of large under-collections recorded in the utilities' balancing accounts. These accounts compare authorized generation revenue requirements to actual revenues collected through rates. Any amounts collected above, or below, authorized revenues are returned to, or collected from, ratepayers. The UOG revenue requirement decreased in 2015 and again in 2016 because costs related to the inactive San Onofre Nuclear Generation Station owned by SCE and SDG&E have been categorized as regulatory costs.

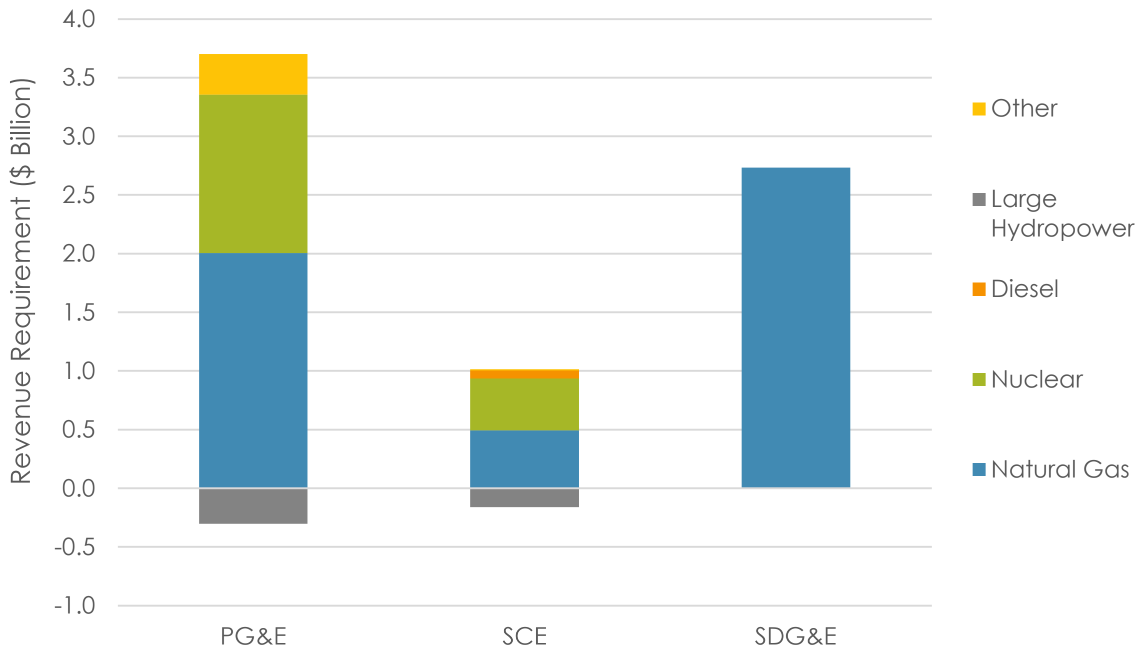
Following electric industry restructuring in the late 1990s and the utilities' divestiture of fossil-fueled generation, UOG (including fuel costs) now accounts for only 2 percent of their combined revenue requirements. The 2020 generation revenue requirement for the electric IOUs is shown in **Table 3.3**.

Table 3.3: 2020 Generation Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	1,256,547	329,816	87,498
Depreciation	553,496	188,205	50,201
Return on Rate Base	428,906	217,293	45,454
Total	**2,238,948**	**735,315**	**183,153**

Figure 3.4 shows the components of the 2020 UOG revenue requirement by sources. PG&E's UOG consists primarily of nuclear power (Diablo Canyon) and several natural gas plants (e.g., the 660-megawatt (MW) Colusa Generation Station, 580 MW Gateway Generating Station, and 163 MW Humboldt Bay Generating Station). SCE's UOG portfolio consists primarily of nuclear (Palo Verde Nuclear Generating Station) and natural gas power plants, including the 1,035 MW Mountain View Power Plant and Peaker plants. SDG&E's UOG includes natural gas plants: the 560 MW Palomar Energy Center, the 96 MW Miramar Energy Facility, the 495 MW Desert Star Energy Center, and the 42 MW Cuyamaca Peak Energy Plant.[24]

Figure 3.4: 2020 Revenue Requirements of UOG Sources[25]



Nuclear Revenue Requirement

SCE and SDG&E hold joint ownership in San Onofre Nuclear Generating Station (SONGS) and SCE holds partial ownership in the Palo Verde Nuclear Generating Station operated by the Arizona Public Service.[26] Due to operating issues at SONGS, this facility was taken offline in the first quarter of 2012 and permanently shut down in June 2013. In 2014, SCE and SDG&E were authorized by the CPUC to purchase replacement power

[24] Desert Star Energy Center was purchased from Sempra Natural Gas in October 2011 and Cuyamaca Peak Energy Plant was purchased in January 2012.

[25] PG&E's and SCE's negative Large Hydropower value is due to lower than forecasted load, which resulted in overcollections. These overcollections were returned to ratepayers in 2020.

[26] In addition to the list of UOG resources above, SCE also owns and operates a diesel generating facility on Santa Catalina Island. Since the island's load is not connected to the grid, the supply and demand are not included in the forecasts, but the expense is included in the revenue requirements.

to alleviate the capacity shortfall. Ratepayer and SCE/SDG&E shareholder responsibilities for SONGS-related costs were determined in a 2014 decision in the SONGS Investigation, which was subsequently re-opened to determine whether that decision represented a fair and equitable balance between ratepayer and shareholder recovery. A final decision on SONGS related costs was issued in August 2018 (D.18-07-037).

As part of SONGS' original coastal development permit issued in 1974, the California Coastal Commission (CCC) required SCE to mitigate adverse impacts on the marine environment. In 2016, as part of that directive, the CCC required SCE to update the configuration of the Wheeler North Reef (WNR), an artificial kelp reef project created in 1999. In 2018, the CPUC approved a settlement agreement in D.18-03-027 which ordered SCE and SDG&E to update WNR forecast costs and present them to the CPUC for approval. Accordingly, the utilities submitted Advice Letters 4052-E (SCE) and 3422-E (SDG&E) with the updated forecast costs, which were approved in December 2019 in Resolution E-5032. Resolution E-5032 authorized 2020 revenue requirement increases of $16.62 million and $4.42 million for SCE and SDG&E, respectively.

PG&E owns and operates the Diablo Canyon Nuclear Power Plant. In January 2018, CPUC approved a joint request by PG&E and other parties to shutter the plant's two generators in 2024 and 2025 (D.18-01-022) and approved ratepayer funding of $241.2 million for employee retention and retraining ($222.6 million) and license renewal activities ($18.6 million). In September 2018, SB 1090 passed and approved an additional $225.8 million in funding for the shutdown of Diablo Canyon Nuclear Power Plant, with $140.8 million of that amount for employee retention programs and $85 million for a Community Impact Mitigation Program (see also D.18-11-024). In total, $467 million in ratepayer funding was approved. Diablo Canyon's 2020 Operating Costs (i.e., O&M) were approximately $358 million while its 2020 capital expenditures totaled approximately $41 million (see D.20-12-005).

SCE owns a 15.8 percent share of the Palo Verde Nuclear Generating Station located near Phoenix, Arizona. Arizona Public Service Company (APS) operates Palo Verde while SCE compensates APS for its 15.8 percent share of expenses. SCE also oversees and reviews Palo Verde operations through participation in two committees. SCE's 15.8 percent share of Palo Verde's 2020 operating costs (O&M) was approximately $75 million while its share of 2020 capital expenditures totaled approximately $37 million (see Application (A.) 19-08-013).

The Nuclear Decommissioning Cost Triennial Proceedings (NDCTP) provide a venue for the utilities to forecast their expected decommissioning costs and for the reasonableness review of recorded costs at their respective nuclear facilities. PG&E's 2018 NDCTP (A.18-12-008) is considering a proposed settlement agreement that would increase annual revenue requirement for Diablo Canyon by $112.5 million annually from 2021 through 2028. A decision is expected by spring 2021 for PG&E's 2018 NDCTP. In addition, the CPUC is still considering the 2018 NDCTP for SONGS (A.18-03-009) in which

SCE and SDG&E request no rate changes. A decision is expected by mid-2021 for the 2018 NDCTP for SONGS.

Apart from the O&M, depreciation and ROR authorized in GRC proceedings, and fuel costs authorized in ERRA proceedings, nuclear generation also results in additional costs, which are collected as separate revenue requirements:[27]

- Fees for disposal and storage of spent nuclear fuel are required by the U.S. Department of Energy (DOE) for temporary and permanent storage facilities. Costs incurred for storage of spent nuclear fuel are currently reimbursed by DOE through claims for prior years consistent with PG&E's 2014 General Rate Case Settlement for Refunding DOE Litigation and Claims Net Proceeds to Customers. In D.07-03-044 the CPUC established the Department of Energy Litigation Balancing Account (DOELBA) to track litigation costs and proceeds received from DOE for the cost of spent nuclear fuel storage on site. SCE and PG&E have been directed to continue to report updated information regarding the net underlying costs supporting the payments from DOE through the litigation and claims process in each nuclear decommissioning cost triennial proceedings (see D.17-5-020 and D.18-11-034).

- Nuclear decommissioning of generating plants at the end of their operating lives is required by the United States Nuclear Regulatory Commission (NRC). To pay for these eventual decommissioning efforts, the utilities were required to establish Nuclear Decommissioning Trust Funds (NDTF). The funds placed into the NDTF are estimated in nuclear decommissioning cost triennial proceedings. The amounts authorized through the nuclear decommissioning costs are funded through rates during the operating lives of the nuclear plants.

Authorized Rate of Return

The authorized rate of return on rate base (ROR) is the weighted average of the cost of capital provided to fund company operations. The cost of capital consists of debt obligations and dividend payments and other company earnings to shareholders. The cost of debt is based on the portion of the utility's capital structure financed by long-term debt (maturation periods greater than one year) and the estimated debt interest rate. The authorized ROE is based on the equity portion of the capital structure (preferred stock and common equity) and the estimated payments to shareholders. The ROE is established prospectively considering the returns on investments in other industries with similar risks. The CPUC authorizes a structure to maintain reasonable credit ratings and to attract additional capital investment.

[27] Nuclear Decommissioning and DOE Decommissioning & Disposal expenses are categorized with Bonds & Fees because they are collected separately.

Figure 3.5 illustrates the CPUC authorized ROR since 2010 for major energy utilities. The figure does not include ROR authorized by FERC for IOU transmission systems; it includes only the ROR authorized by the CPUC for UOG and distribution. **Figure 3.6** shows trends in the CPUC authorized ROE component of ROR since 2010.

Figure 3.5: Trends in Weighted Average Rate of Return (ROR)

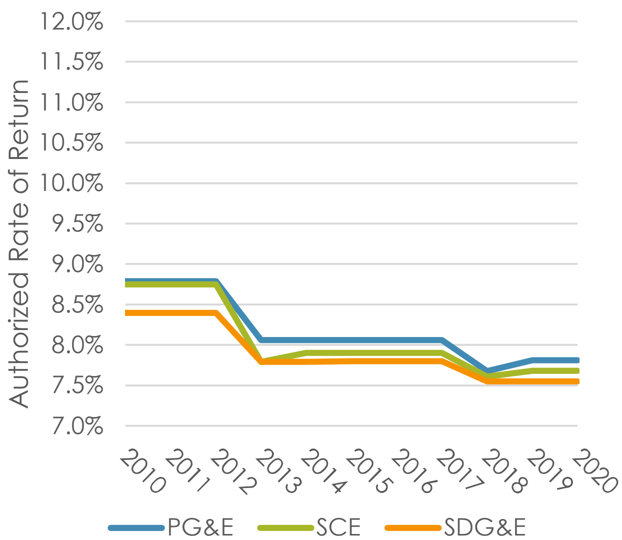


Figure 3.6: Trends in Return on Equity (ROE)

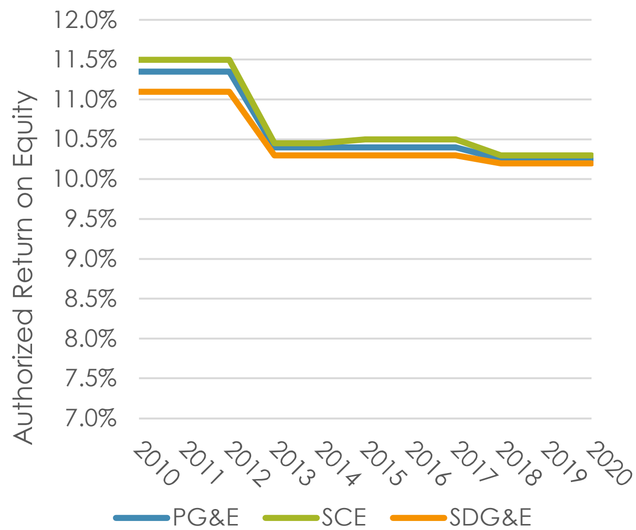
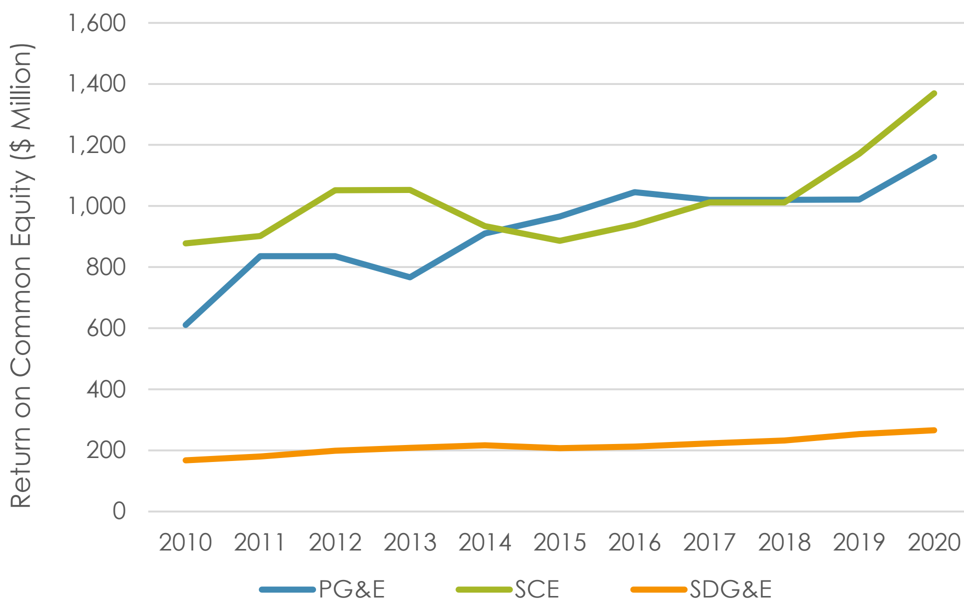


Figure 3.7 shows trends in dollars authorized for return on common equity for major energy utilities since 2010. The figure does not include return on common equity authorized by FERC for IOU transmission systems; it includes only the return on common equity authorized by the CPUC for UOG and distribution.

Figure 3.7: Dollar Trends in Authorized Return on Common Equity



The utilities are currently required to file a cost of capital application every three years, although this review cycle can be, and has sometimes been, extended. In April 2019, SCE, SDG&E, and PG&E filed their 2020 cost of capital applications. In D.19-12-056, the CPUC established the 2020 through 2022 cost of capital for SCE, PG&E, and SDG&E.

Transmission Revenue Requirement

Background and Jurisdictional History

As part of energy restructuring, the CAISO was created by the legislature and given operational control[28] over the utilities' high voltage transmission lines on March 31, 1998, and authority for determining transmission revenue requirements was transferred to FERC.[29] The transmission revenue requirements (TRR) authorized by FERC include the same core components (e.g., cost-of-service, depreciation, cost of capital, and taxes) as the general rate cases at the CPUC.

Components of the electric grid are considered part of the transmission system and under FERC jurisdiction if they are high-voltage and meet FERC criteria for connectivity in the transmission system. Each utility defines its high-voltage transmission lines

[28] The Restructuring Decision (1996) functionally created the implementation of the CAISO through the acceptance of AB 1890 (Sept. 24, 1996).

[29] FERC Order 888 and 889 (April 1996) required utilities to open transmission grids for access by all generators on a nondiscriminatory basis and functionally unbundled rates for generation, transmission, and ancillary services. The CPUC acceded to this regulatory transfer in its Electric Restructuring Decision D.95-12-063 (Dec. 20, 1995).

differently. PG&E, SCE, and SDG&E define all power lines at and above 60 kV, 200 kV, and 69 kV, respectively, as transmission-level assets that are regulated by FERC. These high voltage networked parts of the grid fall under CAISO's operational control and FERC's regulatory jurisdiction. All other electric power lines and assets remain under CPUC regulatory control and jurisdiction.

Currently, the three major IOUs file Transmission Owner (TO) formula rate cases at FERC, establishing rates of depreciation and cost of capital for the next several years.[30] A formula provides a structure through which necessary expenses and capital costs can be implemented, as well as the opportunity for annual true-ups to account for over- or under-collection in rates. Further, a formula prevents the need for an entirely new rate case at FERC every year. As an update to last year's Report, in October 2020, FERC finally issued a final order on most of the issues in PG&E's TO18 rate case, which was litigated in 2017 and 2018 at FERC. However, because FERC has changed its methodology on how to calculate the return on equity ("ROE") a utility can recover from ratepayers on its capital plant, parties, including the CPUC, continue to brief this issue for rates that apply to 2017. The CPUC hopes for a decision on all issues in TO18 in 2021, as the settled outcome of TO19 for 2018 rates is tied to the final decision in TO18.

Transmission Revenue Requirements and Trends

The CPUC is the statutorily-designated agency representing the interests of California retail ratepayers in TO rate cases at FERC.[31] It is FERC's responsibility to approve just and reasonable transmission revenue requirements (TRR) and rates. The CPUC's fundamental role in FERC proceedings is to advocate for containing ratepayer costs in the TO rate cases. To this end, the CPUC actively participates in TO rate cases before FERC to advocate for just and reasonable rates in transmission ratemaking proceedings. Due to the importance and complexity of these rate cases, CPUC Legal Division and Energy Division staff analyze a multitude of expenses and capital projects for cost effectiveness, reliability, safety, and overall prudence of expenditures. Specific TRR components examined include return on equity, taxes, depreciation, cost-of-service, and the forecast of expenses of transmission capital projects.

FERC approves just and reasonable TRRs for the IOUs. [32] When the IOUs file their TRR requests, the CPUC team, other joint intervenors, and FERC staff review, analyze, and critique the filings. These entities also conduct discovery on the utilities' filings to collect evidence and develop a fact-based recommendation on what they believe is a just and reasonable revenue requirement to protect ratepayers. Generally, a FERC Administrative Law Judge (ALJ) facilitates a settlement. If settlement talks come to an impasse, as they did in PG&E's TO18 rate case, FERC sets the case for hearing and

[30] Prior to 2018, PG&E filed a stated-rate case annually at FERC. These annual rate cases typically ended with so-called "black box" settlements where the costs of specific components of the transmission revenue requirement are not provided, but instead a lump sum revenue requirement is settled on to determine rates. Unlike formula rate cases, these annual stated-rate cases provided no opportunity to true-up amounts over- or under-collected in rates.

[31] CPUC Code, Section 307(b).

[32] In general, although the CPUC has jurisdiction over the environmental review and siting of many large and/or capacity expanding transmission projects, FERC has jurisdiction over the revenue requirement for such projects.

ultimately decides how the various rate case components will result in a just and reasonable TRR.

In October 2018, PG&E filed its Twentieth Transmission Owner Formula Rate Case (TO20) at FERC. Settlement of all issues was accepted by FERC on December 30, 2020. The term of the formula rate runs from May 1, 2019 through 2023. Of note in the settling of TO20 was the CPUC's success negotiating the establishment of the Stakeholder Transmission Asset Review (STAR) Process. As over 80% of PG&E's capital projects (i.e., well over $1billion annually) receive no review by the CAISO or CPUC, the STAR Process provides stakeholders with the opportunity to review substantial data on future projects, participate in stakeholder meetings, and seek addition information to understand, and provide input on, PG&E's capital spending.

In SCE's case, parties reached a settlement agreement which SCE filed with FERC on July 1, 2020. FERC approved the certified uncontested settlement offer on September 23, 2020. Significantly, the settlement authorized an annual TRR reduction of $137.4 million for California retail ratepayers. Inclusive in this agreement was a commitment from SCE to establish a Stakeholder Review Process (SRP) for the purpose of review of SCE's Five-Year Transmission Investment Plan ("Five-Year Plan") for transmission projects and expenditures.

SDG&E filed its fifth (TO5) formula rate application at the end of October 2018 and parties successfully negotiated an uncontested settlement approved by FERC on January 24, 2020. The resulting settlement agreement in a TRR reduction of $87.13 million annually for California ratepayers. For the duration of the rate formula SDG&E will file Annual True Up transmission rate filings with FERC to reconcile differences between forecast and actual expenditures and other factors affecting their transmission revenue requirement.

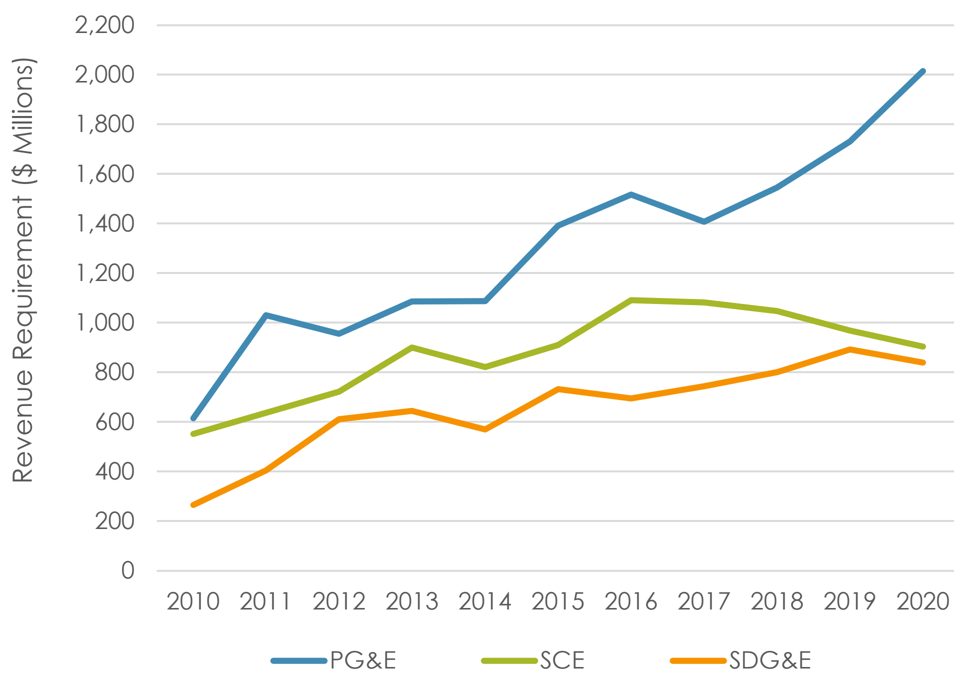
The estimated savings from FERC Transmission cases bring the cumulative savings from 2008 to 2020 to approximately $2.24 billion for California ratepayers. Additional savings from negotiations in the unresolved PG&E rate cases are anticipated.

Even with the savings for ratepayers secured by the CPUC's efforts, transmission revenue requirements for the IOUs have been trending up since 2010, increasing at an average annual growth rate of 11.19 percent for PG&E; 7.32 percent for SCE; and 11.87 percent for SDG&E as shown in **Figure 3.8**. Historically, much of the increase in the IOU's revenue requirements has been due to transmission infrastructure capital investments. In the past years, reasons for these increases have included CAISO reliability and Renewables Portfolio Standard (RPS) mandates, such as replacing and modernizing transmission infrastructure, interconnecting new electric generation to the grid, and compliance with updated North American Electric Reliability Corporation requirements.

The current trend in transmission capital investment shows that all three IOUs are increasing their spending on "self-approved" transmission projects. "Self-approved" means there is no existing requirement that these projects undergo review for cost or need by CAISO, CPUC, or any other third party. In 2020, the three IOUs reported that from 2010 to 2019, these self-approved transmission projects accounted for 41 percent of their collective transmission investment. However, the IOUs forecast that from 2020 to 2024, these unreviewed projects will account for nearly 57 percent of their capital project costs.

While FERC has found that these self-approved projects do not fall under the planning requirements of existing FERC regulations, the CPUC and other stakeholders had success in 2020 negotiating PG&E's Stakeholder Transmission Asset Review (STAR) Process and SCE's Stakeholder Review Process (SRP) as parts of their respective TO rate cases at FERC. These stakeholder processes improve transparency of the two utilities' transmission capital projects planned for the next five years. These are important steps to help ensure that the IOUs are building the right projects in the right locations at the right times for safety and reliability of the modernizing grid.

Figure 3.8: Trends in Transmission Revenue Requirement[33]



[33] Does not include costs related to Reliability Services or Transmission Access Charge.

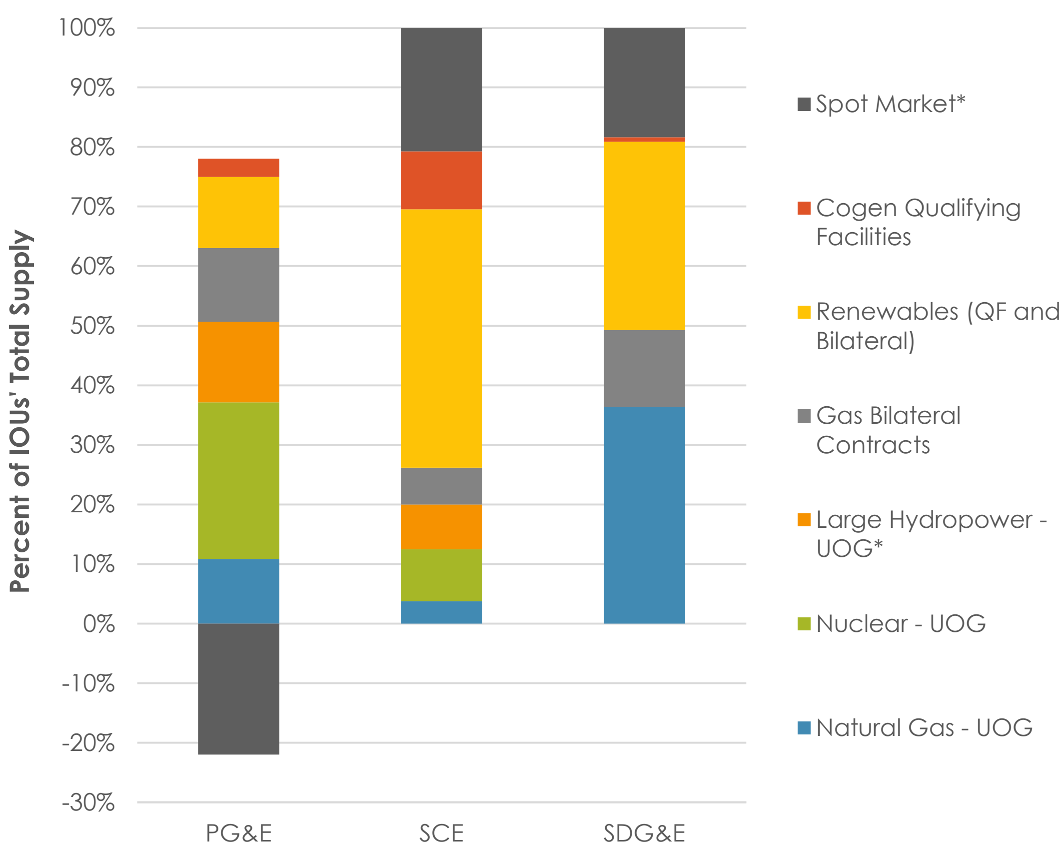
IV. Power Procurement Costs

The generation revenue requirement includes utility owned (or retained) generation (UOG) costs, as well as purchased energy and capacity costs. As previously noted, in the late 1990s the utilities divested almost all of their fossil-fueled generating plants during restructuring, and as a result, they largely rely on purchased power for incremental electricity needs.

In 2020, purchased power accounted for approximately 70 percent of the total generation revenue requirement, while UOG comprised about 6 percent (see **Figure 4.1**). Power purchase costs represent the largest component of forecasted generation costs and accounted for 29 percent of total revenue requirements. Recovery of these pass-through costs is authorized through the ERRA proceedings. The sale of purchased power is expensed, not capitalized.

PG&E's negative spot market value is due to lower forecasted bundled load in 2020, which spurred PG&E to be a net energy seller in the 2020 spot market.

Figure 4.1: 2020 Forecast Energy Supply for Electric Utilities



*Includes Other

Background

Heavy reliance on power purchases rather than UOG began with the enactment of AB 1890 in 1996, which restructured the electric utility industry in California and created the CAISO and the Power Exchange. To create a competitive electricity market in which non-utility suppliers would compete with the utilities in the wholesale generation market, the utilities were encouraged to divest at least 50 percent of their fossil-fueled generation. The CPUC provided a rate of return (ROR) incentive to the utilities to encourage them to divest. As a result, the utilities sold a substantial portion of their fossil-fueled generation.

During the 2000-01 energy crisis, the utilities were exposed to high market prices for electricity, due in large part to the divestiture of their generating plants. Authorized utility rates, which were frozen at pre-restructuring levels from June 1996, were no longer sufficient for the utilities to cover the high costs of purchased power; PG&E filed for bankruptcy and both SCE and SDG&E faced substantial financial uncertainty. In response, the Legislature enacted AB 1X, which authorized the DWR to enter into power purchase contracts to stabilize the severely disrupted energy markets.

In 2002, the Legislature enacted AB 57 to return energy procurement responsibilities to the utilities. The legislation required the CPUC to adopt a Long-Term Procurement Plan to ensure sufficient resource availability over time. The legislation also established guidelines for procurement solicitations, cost recovery of power purchases, and integration of renewable resources using long-term planning. The contracts resulting from these solicitations are reviewed by Procurement Review Groups[34] that the CPUC required the IOUs to create.

AB 380 (2005) further addressed CPUC responsibilities for resource planning, requiring the CPUC, in consultation with the CAISO, to establish resource adequacy requirements to ensure that adequate physical generating capacity would be available to meet peak demand. Consequently, the utilities (and all load-serving entities) are required to maintain a 15-17 percent planning reserve margin for generating capacity to ensure they have sufficient capacity available or under contract to serve their forecasted load.

In addition, SB 1078 (2002) established the RPS and required the utilities to procure 20 percent of their electricity demand from renewable resources by 2017. The statute also required each IOU to hold an annual solicitation to procure renewable power. SB 107 (2006) later increased the RPS obligation to 20 percent by 2010 and was

[34] A Commission authorized forum that reviews procurement activities including contracts and reasonableness criteria and offers assessments and recommendations to each utility. The Commission initially established Procurement Review Groups (PRG) in D.02-08-071 as an advisory group to assess the investor-owned utilities' procurement strategy and processes, as well as specific proposed procurement contracts. The PRG includes non-market participants, as well as Energy Division and Cal Advocates.

updated by SB 2 (2011) when the RPS obligation was raised to 33 percent by 2020. SB 350 (2015) raised the RPS obligation to 50 percent by 2030. In 2018, SB 100 set the current RPS obligation to 60 percent by 2030 and the planning goal of obtaining 100 percent of electric retail sales to end-use customers from renewable energy and zero-carbon resources by 2045.

Types of Purchased Power

DWR Contracts

DWR contracts were long-term contracts that the DWR entered into on behalf of IOU customers during the energy crisis. Each year, DWR submits its revenue requirement to the CPUC for adoption and subsequent collection from, or refund to, ratepayers through the DWR Power Charge. Due to the recent expiration of these contracts, DWR's Power Charge revenue requirement for all three utilities was either negative or zero in 2020 and resulted in a refund of operating reserves to customers. As discussed further below, there was also a DWR bond charge collected separately in electric rates in 2020.

Qualifying Facilities (QFs)

Qualifying Facilities (QFs) are co-generation and renewable generation facilities that qualify to sell power to the utilities under the Federal Public Utility Regulatory Policies Act (PURPA). These facilities must meet FERC's requirements for ownership, size, and efficiency to qualify as QFs. PURPA requires IOUs to interconnect with, and purchase power from, QFs at rates that reflect costs the utility avoids by buying QF power instead of procuring power from other sources. In 2011, the CPUC approved the QF/Combined Heat and Power (CHP) Program Settlement which suspends the "must-take" obligation for QFs over 20 MW and establishes new energy prices for QFs.[35] In 2015, the CPUC adopted an Emissions Reduction Target associated with CHP procurement of 2.72 million metric tons of greenhouse gas (GHG) Emissions Reductions by 2020.[36] In 2020, the CPUC adopted a new Standard Offer Contract for QFs, including new avoided cost energy and capacity prices established either at time of contract execution or at time of product delivery.[37]

Figure 4.2 and **Figure 4.3** break out QF supply and revenue requirements for cogeneration and renewable energy. Since 2005, the total energy supply provided by all QFs has decreased, and the QF revenue requirement has decreased by approximately $1.05 billion. Over the same time period, the revenue requirement for cogeneration QF has decreased as older contracts expire, and the revenue requirement for renewable QF has increased.

[35] QF costs include Competition Transition Charges (CTC). For a breakout, see table in Appendix A.
[36] D. 15-06-028.
[37] D.20-05-006.

Figure 4.2: Trends in Purchased Power Supply (GWh)

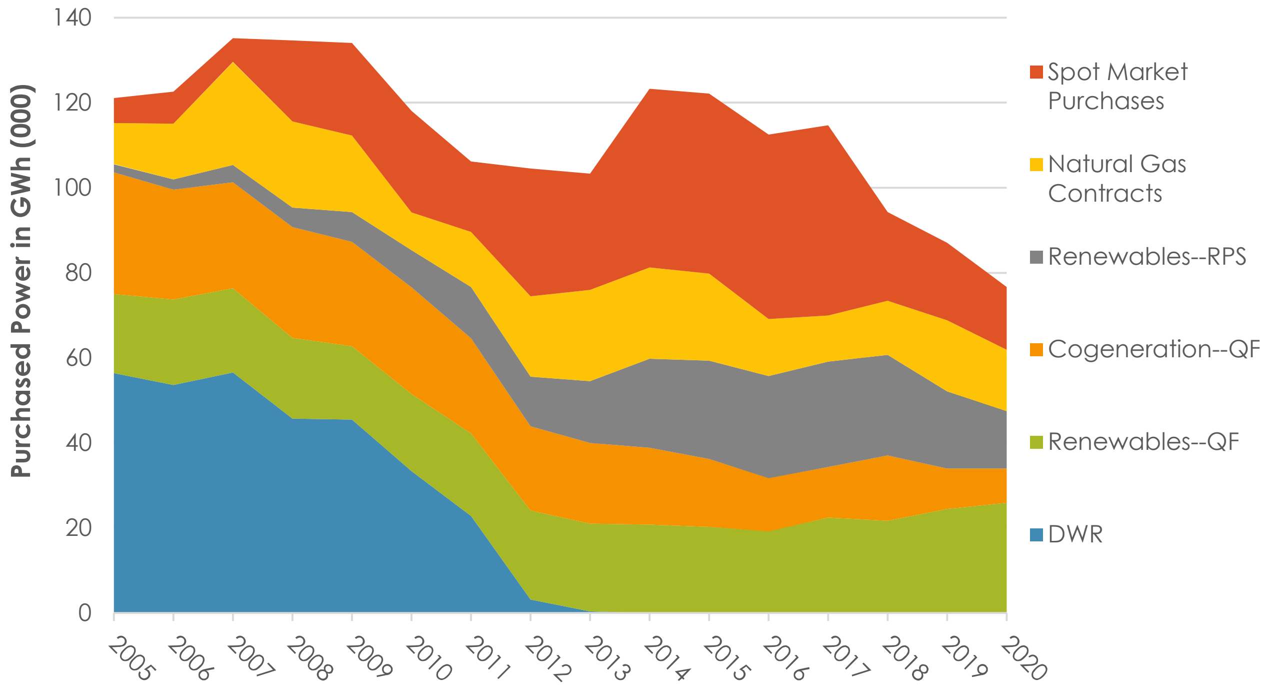
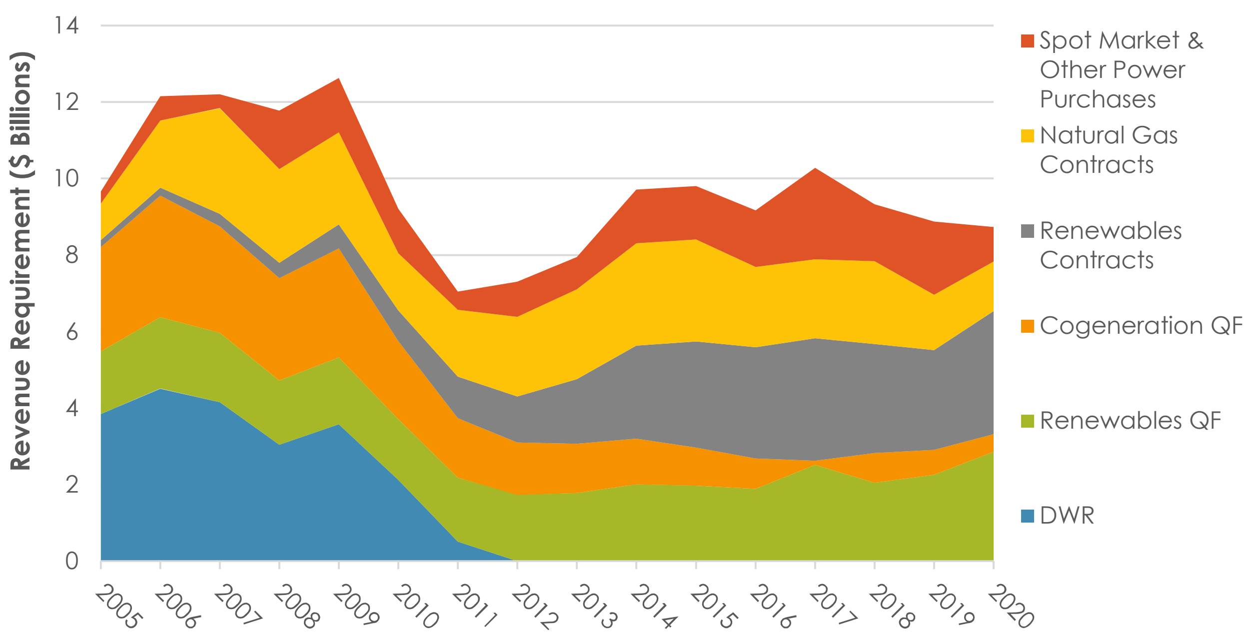


Figure 4.3: Trends in Purchased Power Revenue Requirement



Bilateral Contracts and Capacity Contracts

Bilateral contracts are a standard method for new energy procurement. These contracts are entered into directly between the utility and an independent power supplier, which may be a generator or a trader. The utilities typically select new contracts through a Request for Offers (RFO) open solicitation process. These bilateral contracts include capacity contracts, which are necessary for the utilities to maintain a minimum 15-17 percent planning reserve margin for generating capacity. The requirements for the additional capacity margin fall under the CPUC's Resource Adequacy decisions. Capacity contracts pay generators to be available to produce power and ensure that sufficient capacity is available to meet load. Reserve margins above forecasted loads are necessary to address unplanned outages and operating reserves.

Bilateral contracts became a larger portion of the utility power procurement portfolio as the DWR contracts expired. Subsequent to the energy crisis, the CPUC and the Legislature determined that the IOUs should not rely heavily on spot market purchases, and instead should have a more diversified portfolio. As a result, the CPUC requires long-term resource planning and resource adequacy. The price of long-term contracts can be thought of as a "hedging cost" or "hedging premium" over spot market prices to ensure certainty and stability of prices in the future. Since 2005, the revenue requirements from bilateral contracts have increased by approximately 1 percent annually.[38]

There are a few factors that help to explain the increasing cost of bilateral contracts for long term capacity. First, in 2004, CPUC D.04-10-035 and D.04-01-050 required load-serving entities to maintain a planning reserve margin of 15 percent above peak load for all months of the year. These requirements are primarily met through contracts with natural gas-fueled generators, but new contracts also include solar and energy storage providers. Senate Bill (SB) 2 1X (Simitian, 2011) altered the calculation methodology for wind and solar to consider their Effective Load Carrying Capability, which lowered wind and solar Qualifying Capacity. Thus, additional resources were required to be added to existing contracts for wind and solar resources to meet resource adequacy requirements. Because resources held in reserve exceed expected load, they often operate infrequently, making them more expensive on a per kWh basis.

Second, natural gas prices spiked in 2005 and in 2008, which increased the cost of the natural gas resources for several years. Recent natural gas pipeline outages have caused increases in the cost of natural gas in southern California. Thus, the fall in natural gas prices seen across the United States has not occurred in Southern California, where prices remain above the national average. Finally, many bilateral contracts are for new facilities, which are more expensive than the older, depreciated plants because of the up-front capital costs.

[38] Bilateral contracts represent natural gas contracts only.

In addition, because approximately 10 percent of electric demand occurs for less than 120 hours per year, a significant amount of electric capacity is only needed for a few peak hours each year. The increasing amount of solar energy in California has also created a steeper demand curve over the course of each day. Plentiful solar power in the midday pushes down net demand in the early afternoon, requiring few additional natural gas power plants to meet the demand. However, the surge of people returning home coincides with the declining solar output, requiring additional (non-solar) units to come online to meet the evening demand (i.e., the "duck curve").

Natural gas-fueled generation and energy storage are needed on the evening ramp to supply peaking and firming capacity because these units can start and ramp-up quickly. Peaking capacity generally costs more per kWh because it is used in only a few peak hours per year and thus capital costs are spread over fewer hours. Recently, the utilities have added new peaking capacity to meet overall capacity requirements, particularly in transmission-constrained areas, increasing resource adequacy costs. As a result, UOG and contracted natural gas-fired generation costs are higher than would otherwise be expected considering recent low gas prices.

Renewable Energy Procurement

The IOUs exceeded their 33 percent RPS requirement by 2020 through a combination of online generation and excess or "banked" renewable energy credits, or RECs. During 2020, the IOUs served a forecasted 52 percent of their generation from eligible renewable resources. The IOUs have forecasted RPS percentages over 60 percent by 2023. From 2003 to 2019, the weighted average time-of-delivery adjusted price of contracts approved by the CPUC has increased from 9.4 ¢/kWh to 10.0 ¢/kWh in nominal dollars which has increased slightly from 6.2 ¢/kWh in 2018.[39]

Other Power Purchases

Additional power purchase and sale mechanisms exist to ensure that the utilities secure sufficient capacity to balance load across the grid and meet peak load requirements at least cost.

- **Spot Market Purchases:** This term refers broadly to power that the utilities buy from the CAISO's Day-Ahead market to balance the system on a day to day basis. IOUs use the spot market to balance their forecasted load requirements for the following day through transactions that may occur in the CAISO market.
- **Net Long Sales:** These are sales that the utilities make when their expected supply exceeds their forecasted load. These sales reduce ratepayer costs by generating revenue from excess capacity not likely to be needed.

[39] The increase in 2020 was due to mandated bioenergy procurement.

- **<u>Inter-Utility or Power Exchange Agreements</u>:** Traditionally, regulated utilities enter into seasonal and long-term inter-utility exchange agreements with other regulated utilities and other load-serving entities. Through bilateral negotiations the specific terms are crafted to best fit the resources and needs of both parties. Payment is typically in the form of non-cash exchanges of capacity and energy balanced to reflect the seasonal and locational value of the power. Different peaking times in the northwest and southwest lead to large-scale transactions.
- **<u>Real-Time Market and Reliability Services:</u>** CAISO has certain agreements with generators to provide reliability services. The CAISO spreads the costs of these reliability services among the load-serving entities. In addition, the CAISO buys power in the real-time market to balance resources and loads and charges the load-serving entities whose short supply necessitated real-time purchases.

Greenhouse Gas Costs and Allowance Proceeds

Since January 1, 2013, electric utilities have been regulated under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the electric utilities must secure compliance instruments - offsets and allowances - and surrender them to the California Air Resources Board (CARB) to account for their GHG emissions. CARB holds quarterly allowance auctions where entities can buy and sell allowances. IOUs can also procure compliance instruments on secondary markets, or through contractual arrangements.

The Cap-and-Trade Program requires the utilities to comply on their customers' behalf for the emissions associated with the energy they use. For electric utilities, compliance costs come in the form of a direct compliance obligation for utility-owned generators and generators under contract (which must also buy and surrender compliance instruments), as well as indirect costs from wholesale market transactions or power contracts with pricing terms that include GHG emission costs.

Beginning in 2014, the electric utilities started introducing Cap-and-Trade-related costs into electricity rates and distributing allowance proceeds to customers via the Climate Credit, applied to customer bills twice a year.

In 2020, the electric IOUs collectively included approximately $149 million in GHG costs into rates and returned approximately $771 million in allowance proceeds to customers in the form of customer credits (see **Table 4.1**).

Table 4.1: 2020 Summary of Greenhouse Gas Costs and Allowance Proceeds[40]

Utility	2020 Electric GHG Revenue Requirement	2020 Electric Proceeds Distributed to Customers
PG&E	(106,488,670)[41]	($340,159,000)
SCE	$195,845,382	($345,008,237)
SDG&E	$60,110,701	($86,104,501)
Total	**$149,467,413**	**($771,271,738)**

Each year, CARB allocates allowances to electric utilities on behalf of their ratepayers. The Cap-and-Trade regulation requires the investor-owned electric utilities to sell all of these allowances at CARB's quarterly allowance auctions in the year they are allocated. The proceeds the utilities receive from the sale of GHG allowances must be used exclusively for ratepayer benefits, consistent with the goals of AB 32 ("The California Global Warming Solutions Act," Nunez, 2006), CARB regulations, and as directed by the CPUC. Consistent with the direction in SB 1018 (2012), the CPUC has determined the methodologies the utilities should use to return proceeds to industrial customers ("emissions-intensive and trade-exposed"), small business, and residential customers.

In addition to customer credits, up to 15 percent of allowance proceeds are used for clean energy or energy efficiency programs. AB 693 (Eggman, 2015) directed up to $100 million of allowance proceeds be allocated annually to solar energy systems in disadvantaged communities. In response, the CPUC established the Solar on Multifamily Affordable Housing (SOMAH) program in December 2017. In 2020, CPUC determined that as proceeds are available and there is adequate participation and interest in SOMAH program, allocation of funds to the SOMAH program will continue through June 30, 2026. In 2018, in response to AB 327 (Perea, 2013), the CPUC developed the Disadvantaged Communities Single-family Solar Homes program (DAC-SASH; $10 million, annually), and the Community Solar Green Tariff and DAC-Green Tariff programs (funding provided as needed and available) to encourage growth of renewable generation among residential customers in disadvantaged communities, both of which are funded first with allowance proceeds and, if those are exhausted, through public purpose programs (PPP) funds. Additionally, in 2019 CPUC also approved use of $20.4 million by SCE for a Clean Energy Optimization Pilot.

[40] Recorded through September 30, 2020 and estimated through December 31, 2020 for proceeds for SDG&E and PG&E; SCE forecast; SCE forecast. 2020 forecasted revenue requirement. Proceeds for bundled and unbundled customers; costs for bundled customers only.

[41] As the amount of departed load increases over time, PG&E has sold electricity procured for former bundled customers to CAISO. As the CAISO sales price reflects GHG costs, PG&E has booked the GHG compliance cost amount associated with electricity sold to CAISO as a negative GHG cost. In 2019, for the first time, indirect negative GHG compliance costs surpassed direct GHG compliance costs associated with utility-owned generation and other purchase agreements, resulting in an overall net negative GHG compliance cost. In D.19-02-023 the CPUC recognized it is feasible for PG&E to achieve negative indirect emissions as a net seller at CAISO. In 2020, PG&E once again forecasted negative GHG costs.

In response to the COVID-19 pandemic, CPUC approved two decisions in April and May of 2020 that expedited the disbursement of the 2020 residential California Climate Credits. CPUC ordered SCE, PG&E, and Pacific Power to split the October Credit into two equal credits and apply each to customer bills in spring and summer months rather than have customers wait until fall. Liberty Utilities was also ordered to advance, but not split, their October credit into the summer months. In total, these changes expedited the distribution of about $350 million in on-bill residential California Climate Credits. These changes impacted only the 2020 credit; distribution is returning to the standard April and October cycle for 2021.[42]

Other Factors Affecting Electricity Generation Costs

Prior sections have described many factors that cause energy generation and procurement costs to vary significantly between different types of procurement and over time. Natural gas prices are another factor that can have a significant effect on the cost of many types of generation:

> **Natural Gas Prices:** Gas prices cause generation costs to be more volatile than other forms of generation. Electric spot market purchases, DWR contracts, and cogeneration QFs costs fluctuate and track with gas prices. Natural gas bilateral contracts do not track as closely with gas prices, as most of the costs of those contracts are associated with capacity and not energy. Renewables contracts generally exhibit more cost stability because they are not reliant on gas prices.

If generation costs are significantly higher or lower than forecasted,[43] the affected utility must file an ERRA Trigger notification with the CPUC's Energy Division. If the utility does not believe that the difference will be within the threshold amount within 120 days, it files an expedited ERRA application (Trigger) that corrects rates to be in line with the costs the utility is experiencing. The interim nature of the Trigger application maintains rate stability if the costs associated with fuel and purchased power vary greatly from forecasted amounts.

The CPUC conducts annual Compliance ERRA reviews that true-up any difference from the utility's forecasted revenue requirement to the actual costs incurred regardless of whether or not a Trigger application was filed.

[42] San Diego Gas & Electric was not directed to advance the distribution of the residential California Climate Credit because they were previously authorized in 2019 to follow an altered 2020-2021 distribution schedule. SDG&E's changes were made to test if improvements in customer engagement and awareness of the credit could be achieved by altering the distribution timing to summer months. For 2020 and 2021, SDG&E distributes the residential California Climate Credit in August and September rather than April and October.

[43] The utility must alert the CPUC if a balance grows to greater than 4 percent more or less than revenue requirement per D. 02-10-062; if the balance is expected to cross 5 percent the utility must file an expedited application known as an "ERRA Trigger Application".

Initially, during the COVID-19 Pandemic, natural gas prices fell as demand for natural gas fell. This decrease in prices helped to offset the overall decline in demand for electric sales and prevented undercollections from occurring in utility generation regulatory accounts.

Weather: Weather continues to play a role in varying electricity prices. The summer heat waves of 2020 throughout California caused electricity prices to spike to extreme highs during peak demand hours. Variances in cost due to weather are addressed in the CPUC's annual ERRA Compliance and ERRA Forecast applications.

V. Demand-Side Management and Customer Programs

Demand-Side Management (DSM) involves various programs and activities on the customer side of the meter to reduce, curtail, or shift demand for electricity through energy efficiency, demand response, or self-supply through distributed generation. In 2003, the CPUC and the California Energy Commission adopted the Energy Action Plan to establish goals for the state's energy strategy.[44] The plan established that cost-effective energy efficiency and demand response are at the top of the loading order and are therefore the preferred means for meeting the state's growing energy needs, followed by renewable energy and distributed generation.

The revenue requirements for DSM primarily consist of financial incentives to encourage DSM activities and the administrative costs to manage these programs. To achieve the goals established in the Energy Action Plan, spending on DSM has experienced a 19 percent average annual increase since 2010. Energy efficiency savings have increased during the same time period. Electricity savings for 2019 were 20 percent above what they were in 2010; and therm savings in 2019 were 300 percent above the 2010 values. In 2020, DSM programs combined accounted for 3.0 percent of the total revenue requirement. In addition to DSM, California also mandates customer programs to provide rate discounts and energy efficiency improvements for low-income customers. **Table 5.1** shows the DSM and customer program costs recovered in rates.

[44] The Energy Action Plan was updated in 2005 and 2008.

Table 5.1: 2020 Demand Side Management and Customer Programs Costs ($000)[45]

	PG&E	SCE	SDG&E	Total
Energy Efficiency[1]	58,592	46,541	71,388	**176,521**
Demand Response	78,604	21,483	14,736	**114,822**
California Solar Initiative	7,955	0	0	**7,955**
Self-Generation Incentive Program	59,851	56,637	20,070	**136,558**
Electric Program Investment Charge	97,834	76,900	16,280	**191,015**
New Home Solar Partnership[2]	(21,935)	(112,589)	0	**(134,524)**
California Alternative Rates for Energy Admin[3]	91,616	(8,531)	124,112	**207,197**
Energy Savings Assistance	71,412	65,808	13,145	**150,364**
Other PPP Programs[4]	13,794	98,669	52,512	**164,975**
Other Regulatory[5]	(295,863)	41,578	158,373	**(95,912)**
Total	**161,861**	**286,496**	**470,616**	**918,972**

1. On site installations were stopped due to COVID-19 health restrictions, resulting in program costs dropping 40% compared to 2019.
2. PG&E and SCE over-collected for the new home solar partnership balancing account. These overcollections were returned to ratepayers in 2020.
3. SCE and SDG&E forecasted an over-collection in the CARE balancing account to be returned to ratepayers.
4. Increase in Other PPP Programs is due to inclusion of SJV Disadvantaged Communities Pilot Balancing Account in 2020.
5 The increase in Other Regulatory for SCE since 2019 is due to no Environmental Enhancement and RCRA Offset reported in 2020. The higher Other Regulatory for SDG&E is due to a higher Electric Distribution Fixed Cost Account and the Total Rate Adjustment Component compared to the other IOUs. The negative value in Other Regulatory for PG&E is due to adjustments from the Greenhouse Gas Revenue Balancing Account.

Energy Efficiency

In 2003, the California Energy Action Plan set energy efficiency at the top of the loading order, determining that the state should maximize all cost-effective energy efficiency investment over both the short and long-term. In D.04-09-060, the CPUC translated this policy into specific annual and cumulative numerical goals for electricity and natural gas savings by utility service territory, which are updated periodically as provided for in that decision. The CPUC-adopted energy savings goals are expressed in terms of annual and cumulative gigawatt hours (GWh), million-therms (MMtherms), and peak megawatt (MW) load reductions.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of rates. The electric portion is funded through the Procurement Energy Efficiency Balancing Account (PEEBA) to reflect the avoided generation and transmission and distribution upgrades that result from reduced electricity demand. The aggregated annual expenditures are approximately $800 million for 2019 and 2020 together (see **Table 5.2**).

[45] Revenue requirement for Demand Side Management, California Solar Initiative, Self-Generation Incentive Program, and other regulatory (-$149 million for PG&E, $120 million for SCE, and $133 million for SDG&E) is collected through the distribution rate component.

The expenditures for 2020 were significantly lower than 2019 due to factors related to COVID-19. In-person energy efficiency installations and other programmatic efforts were significantly affected due to COVID-19 health restrictions, resulting in the energy efficiency portfolio only reaching 47 percent of the budgeted amount as of the third quarter of 2020.

Programmatic efforts over this time resulted in reported program savings of 1,602 GWh (or 258 MW) and 55 MMtherms.[46] According to the EPA,[47] that is enough electricity savings to power about 130,704 homes for one year, and enough gas savings to avoid the need for about three-quarters of a coal power plant.

These programs support residential, public, commercial, industrial, and agricultural sectors to overcome barriers to improving energy efficiency and realize savings for the ratepayer. In addition to the directly quantifiable savings and benefits, the CPUC also supported programmatic activities targeted at the long-term transformation of consumer energy markets through emerging technology development, marketing, education, training, and other initiatives. However, the savings benefits associated with these efforts are difficult to quantify and the CPUC has historically not done so.

[46] Reported savings estimates are net and are available from CEDARS (https://cedars.sound-data.com/).

[47] Equivalencies estimated using the EPA Greenhouse Gas Equivalencies Calculator (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator).

Table 5.2: Savings and Expenditures from Non-Codes and Standards IOU Program[48]

Year	2020	2019	Grand Total
All Investor Owned Utilities			
Electric (GWh)	**490**	**1112**	**1602**
Demand (MW)	**60**	**198**	**258**
Natural Gas (MMTh)	**20**	**35**	**55**
Carbon (1000 Tons CO2)	**306**	**722**	**1029**
Total Expenditures ($M)	**$237**	**$559**	**$795**
PGE			
Electric (GWh)	294	536	**829**
Demand (MW)	51	96	**147**
Natural Gas (MMTh)	7	12	**20**
Carbon (1000 Tons CO2)	149	323	**472**
Total Expenditures ($M)	$107	$264	**$370**
SCE			
Electric (GWh)	152	431	**583**
Demand (MW)	7	76	**83**
Natural Gas (MMTh)	0	0	**0**
Carbon (1000 Tons CO2)	59	201	**260**
Total Expenditures ($M)	$60	$135	**$194**
SoCalGas			
Electric (GWh)	1	9	**9**
Demand (MW)	0	2	**2**
Natural Gas (MMTh)	13	22	**35**
Carbon (1000 Tons CO2)	76	133	**210**
Total Expenditures ($M)	$43	$95	**$138**
SDGE			
Electric (GWh)	44	136	**180**
Demand (MW)	1	25	**26**
Natural Gas (MMTh)	0	1	**1**
Carbon (1000 Tons CO2)	22	64	**87**
Total Expenditures ($M)	$27	$66	**$93**

[48] Table Notes: 2020 data does not include fourth quarter data which will be available May 1st, 2021; Savings data does not include REN/CCAs or Codes and Standards advocacy savings; Savings data is reported net, first-year savings; Data does not include Energy Savings Assistance Program savings and costs; IOU Expenditures are reported at the program level and are not broken down into gas vs. electric expenditures. The total EE budget for 2020 was $557 million.

Demand Response

Demand response is defined as the change in customer electricity usage (typically reducing use or shifting use to other times in the day) at peak periods in response to economic incentives, price signals, environmental conditions, or reliability signals. Effective demand response programs provide California ratepayers with various economic and environmental benefits, such as:

1) Saving ratepayer money by deferring capital expenditures to build power plants by avoiding the use of older, less efficient power plants that would otherwise be necessary to meet peak demand.
2) Decreasing the price of wholesale energy and resulting retail rates through peak demand reductions and avoiding the purchase of high-priced energy.
3) Providing greater reliability to the grid, which helps prevent blackouts.
4) Avoiding the consumption of fossil fuels which can reduce GHG emissions.

Demand Response Customer Programs

Demand Response (DR) goals are met through customer bill credits or payments to participate in DR programs that aim to curtail load to meet system reliability or peak capacity management needs.

Some DR programs operate with the use of dynamic pricing programs and time-variant rates in which price signals encourage customers to shift their energy use to off-peak periods of the day when energy demand is lower, such as time of use (TOU), critical peak pricing (CPP), peak time rebate (PTR), and real time pricing (RTP). While other demand response programs such as the Base Interruptible Program (BIP), Capacity Bidding Program (CBP), or Air Conditioning Cycling (A/C Cycling), etc.) are bid as a resource into CAISO energy markets, enabling them to compete against generation bids and to be dispatched as needed by the CAISO.

Future DR programs are expected to help integrate increasing amounts of renewable power onto the grid by shifting electric loads to periods of high renewable generation. There may also be a significant role for DR to alleviate electricity supply shortages in certain local areas of the state with constraints on transmission capacity.

Evolution of Demand Response Programs

DR programs were historically aimed at large commercial and industrial customers that can shed significant amounts of load as an immediate or day-ahead response. DR programs for residential customers also exist (e.g., AC Cycling), and with the advent in recent years of smart meters, smart thermostats, batteries, and other smart devices, residential customer participation has grown. Additionally, some DR programs are managed by third-party operators also known as "Aggregators" or "Demand Response Providers," which provide customers with additional choices beyond programs run by utilities. The addition of third-party operators to utility DR programs is intended to stimulate competition to innovate and offer the best value at the lowest cost.

The costs for DR programs include administration, incentives, marketing/customer education, measurement/evaluation, IT infrastructure, and pilots. One of the third-party programs – the DR Auction Mechanism (DRAM) – is operated outside the utility program portfolios. DRAM provides a pathway for third-party DR providers and their customers to receive capacity payments for providing such load shedding services during periods of peak electricity demand and high prices. Under the DRAM pilot, utilities procure capacity through bids that include all costs except for utility technology incentives, and limited utility marketing.

In response to Energy Division's 2019 DRAM Evaluation Report, the CPUC altered the design of the DRAM pilot to improve performance and reliability of DRAM resources and extended the DRAM pilot for four years (2020-2023). Specifically, the CPUC instituted new program requirements for more accurate estimates of resource capacity (MW), adopted a more sophisticated capacity payment structure that penalizes underperformance, and imposed minimum resource dispatch activity requirements.

Pursuant to the DRAM decisions, the IOUs conducted DRAM auctions for 2020 and 2021 and procured 216 MW and 206 MW (August capacity) for the respective years from third-party DR providers. Per the annual DRAM refinement process authorized in D.19-07-009, Energy Division held several DRAM Working Group sessions in 2020 to discuss a variety of potential refinements to DRAM, some of which were adopted in a Resolution to apply to the DRAM auctions for 2022 and 2023. Currently, Nexant Inc., a consultant, is conducting a follow up evaluation of the DRAM pilot. Their evaluation report is expected to be available in the fourth quarter of 2021.

As an alternative pathway to participate in DRAM, the CPUC established a Load Impact Protocol review process to qualify third-party DR providers to provide DR capacity for electric resource adequacy (RA) to non-IOU load serving entities (LSEs), such as community choice aggregators and energy service providers. Five DR providers applied; three providers successfully completed the review process and qualified to offer RA eligible DR capacity of up to 217 MWs in 2021 to non-IOU LSEs.

In alignment with the state's focus on reducing GHG emissions, the CPUC prohibits the use of customer-owned fossil fuel generators during DR events as of January 1, 2019. The CPUC is currently considering whether monitoring devices should be required on the generators as part of a verification mechanism.

Since DR participates in the electricity markets, the CPUC evaluated DR performance in the *Final Root Cause Analysis Report*.[49] In response to the 2020 rotating outages in the CAISO footprint caused by an extreme heat storm from August 14 through 19, 2020 with

[49] *Final Root Cause Analysis, Mid-August 2020 Heat Storm*, published on January 13, 2021, available at https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Final_Root_Cause_Analysis_MidAugust_2020_ExtremeHeatWave.pdf.

temperatures ten to twenty degree above normal, the CAISO, CPUC, and CEC jointly prepared the *Final Root Cause Analysis Report*, which examined the condition and events of August 14 and 15, 2020, including the performance of DR resources during the heat wave using customer meter settlement data. The *Final Root Cause Analysis Report* also provided recommendations for immediate, near, and longer-term improvements to statewide electricity resource planning, procurement, and market practices, some of which involve DR. Some of those recommendations are now under consideration in the CPUC Rulemaking (R.) 20-11-003.[50]

Customer Generation

Over the past several years, the CPUC has taken actions that support the development of customer-sited distributed energy resources and related technologies by providing financial incentives to customers and project developers. Ratepayers fund Distributed Generation (DG) programs that provide financial incentives to participating customers – the California Solar Initiative (CSI), the Self-Generation Incentive Program (SGIP), and the Solar on Multifamily Affordable Housing (SOMAH) program. In addition, Net Energy Metering (NEM) provides customer-generators with bill credits for power generated by their onsite systems that is fed back into the grid.

California Solar Initiative (CSI)

Established in 2006, the CSI program provided either up-front incentives or performance-based payments for the installation of photovoltaic solar systems up to 1 MW on existing residential homes as well as existing and new commercial, industrial, government, non-profit and agricultural properties within the service territories of the IOUs. The CSI program set a budget of $2.367 billion over 10 years and a goal of reaching 1,940 MW of installed solar capacity from the general market program and two low-income programs.[51] Additionally, the CSI Thermal program, which incentivizes gas-displacing solar technologies, was launched in 2007 and has a budget of $250 million and a goal of establishing a mainstream market for solar thermal systems that directly reduces demand for natural gas in California.

- The CSI General Market incentive program closed on December 31, 2016. Program administration continued until December 31, 2019 to allow time for CSI program administrators to process remaining performance-based payments. The CSI low-income programs – the Single-family Affordable Solar Housing (SASH) program and Multifamily Affordable Solar Housing (MASH) program – are ongoing, though only in certain IOU territories where the incentives are not fully reserved, or where reserved funds went unused and became available.

[50] CPUC R.20-11-003, November 20, 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M351/K809/351809897.PDF.

[51] The low-income CSI programs were extended in 2015 and received an additional $54 million each, which increases the total CSI budget to $2.475 billion through 2021.

- The installed capacity under the CSI General Market program was 1,897 MW. As of January 2021, 53.7 MW of capacity were installed under the MASH Program and 29.4 MW were installed under the SASH Program.[52] The MASH Program funding has been exhausted. As of January 2020, an estimated 12,021 solar thermal systems were installed on the customer side of the meter.

Self-Generation Incentive Program (SGIP)

Established in 2001, SGIP provides incentives to support distributed energy resources that will result in reductions in GHG emissions and peak demand. SGIP is one of the longest-running DG incentive programs in the country. Since the program's inception, over $2 billion in SGIP incentives have been paid out or reserved to over 30,000 projects comprising over 1.3 gigawatts of capacity. In 2020, over $440 million was paid out or reserved to over 15,000 projects comprising over 271 MW of capacity; all but $6.9 million went to energy storage systems.[53]

- The program was reauthorized by SB 700 (2018) to continue ratepayer collections through 2024 and program administration through 2026. Pursuant to SB 700, the CPUC authorized ratepayer collections of $166 million annually for the years 2020 to 2024 in Decision 20-01-021 for a total of $830 million. The program funds are collected from PG&E, SCE, SDG&E, and SoCalGas.
- CPUC D.20-01-021 allocated the $830 million authorized in new ratepayer collections across the SGIP budget categories: 88 percent to energy storage and 12 percent to renewable generation. Within energy storage, an additional $512 million was allocated to the equity resiliency budget created in D.19-09-027. This budget provides the highest incentive level to vulnerable households and facilities that support vulnerable communities to enable these groups to enhance their resiliency in the face of wildfire risks and related de-energization events.
- Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells and advanced energy storage systems. For non-residential systems, half of the incentive is paid up-front and half of the incentive is paid based on the performance of the technology over five years.

[52] Source available at https://www.californiadgstats.ca.gov/.

[53] *SGIP Weekly Statewide Report*, available at (selfgenca.com/home/resources).

Solar on Multifamily Affordable Housing (SOMAH) Program

Assembly Bill (AB) 693 (Eggman, Chapter 582, 2015) directed the CPUC to develop a program that provides financial incentives for the installation of solar energy photovoltaic (PV) systems on multifamily affordable housing properties throughout California. The CPUC issued D.17-12-022 that outlined the program design for the new SOMAH program in the service territories of PG&E, SCE, SDG&E, Liberty Utilities, and PacifiCorp. In addition to building on many of the program successes and lessons learned from the CSI-funded MASH Program, the SOMAH program seeks to:

- Direct up to $100 Million, annually, from the electric IOUs' Greenhouse Gas Auction Proceeds towards subsidized solar energy systems on multifamily affordable housing.
- Encourage the development and installation of solar systems in California's disadvantaged communities.
- Develop, by December 31, 2030, at least 300 MW of installed solar generating capacity.

The SOMAH Program opened on July 1, 2019, with more than 200 applications received on day one, and waitlists were started in the PG&E, SCE, and SDG&E service territories. By the end of 2020, 490 applications had been submitted into the program, with participation in all five SOMAH-eligible IOU territories. On opening day, the SOMAH program surpassed the initial 15 MW target set forth by the SOMAH Program Administrator, receiving applications totaling 74 MW. With the initial MW target goals met within the first day of launch, the SOMAH PA has developed and begun to implement strategies to ensure a robust pipeline of applications. In April 2020, the CPUC issued D.20-04-012, which allocated additional funds to the program until 2026. As of January 2021, the program has received an additional 29 MW of applications.

Net Energy Metering (NEM)

Residential and commercial customers who install small RPS-eligible generation facilities to serve all or a portion of onsite electricity needs are eligible for the state's NEM program. NEM allows customer-generators to receive a full retail-rate bill credit for energy generated by their on-site system that is fed back into the utility grid during times when on-site generation exceeds a customer's energy demand. The credit is used to offset the customers' electricity bills and may be rolled over to subsequent billing periods for up to a year.

In January 2016, the CPUC approved a decision adopting a NEM successor tariff (NEM 2.0) for customers receiving NEM service after each IOU reached its 5 percent NEM capacity cap. The current NEM 2.0 program went into effect in SDG&E's territory on June 29, 2016, in PG&E's territory on December 15, 2016, and in SCE's territory on July 1, 2017. Customers on NEM 2.0 must pay an interconnection fee, and pay non-bypassable charges on each kWh of energy they consume from the grid within a metered interval, and take service on a time-of-use rate.[54]

In December 2019, following a competitive bid process, Verdant Associates,[55] Energy and Environmental Economics, Inc. (E3), and ILLUME Advising were chosen to conduct a formal and independent evaluation of NEM 2.0. ILLUME conducted an evaluation of the California Solar Consumer Protection Guide, resulting in a June 2020 memo.[56] The evaluation's focus groups had low prior awareness of the guide, but found it useful. ILLUME recommended improvements that the CPUC then made in September 2020.

Verdant, with the assistance of E3, analyzed the costs and benefits to both customers and utilities of customer-sited renewable resources taking service on NEM 2.0, and released a draft report in August 2020.[57] This study evaluated the cost-effectiveness of the NEM 2.0 tariff for society, participants, program administrators, and ratepayers. It found that the tariff is cost-effective overall for NEM 2.0 participants, but is not cost-effective from a combined participant/utility perspective or for non-participating ratepayers.[58] The study also compared the cost for the utility to serve NEM 2.0 customers—based on the customer's grid usage and fixed costs of service—against their total bill payments. It found that prior to NEM 2.0 system installation, both residential and nonresidential NEM 2.0 customers pay more in their utility bills than their estimated costs of service, on average. Post-installation, the average residential customer pays less, and the average nonresidential customer pays more, than the estimated utility cost to serve them.[59] Verdant accepted informal stakeholder comments in September 2020 and finalized the report in January 2021.

In August 2020, the CPUC opened a new proceeding, Rulemaking (R.) 20-08-020, to revisit the NEM successor tariff. One of the primary goals of the proceeding is to incorporate information that has become available since 2016 to enable California's compensation program for customer-generators to better fulfill its statutory requirements (in AB 327, Perea 2013). The proceeding will reference the NEM 2.0 evaluation and a white paper on possible compensation mechanisms for customer-generators authored by E3.

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[54] For purposes of the NEM successor tariff, the relevant non-bypassable charges are: Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges.

[55] The contract was originally awarded to Itron and was transferred to Verdant Associates in Summer 2020.

[56] The memo is available at https://www.cpuc.ca.gov/solarguide.

[57] The draft and final reports are available at https://www.cpuc.ca.gov/nem2evaluation.

[58] The draft report found that NEM 2.0 is cost-effective from a combined participant/utility perspective due to a modeling error, but we report the final report's findings above for clarity on the conclusions that should be taken away.

[59] The study also provided analysis, not summarized here, regarding customers' energy usage before and after installing renewable energy generation systems on the NEM 2.0 tariff, effects on cost-effectiveness of the addition of energy storage or the removal of the federal investment tax credit, cost-effectiveness compared to NEM 1.0, characteristics of the NEM 2.0 participant and non-participant populations, and other topics.

Low-Income Programs

In addition to the low-income and disadvantaged community programs mentioned previously, the IOUs provide three ratepayer-funded energy assistance programs for qualifying low-income customers meeting the income limits at or below 200 percent of federal poverty guidelines. The California Alternate Rates for Energy program (CARE) offers rate discounts off energy bills for low-income customers, and the Energy Savings Assistance program (ESA) provides no-cost in-home weatherization services, energy efficiency measures, and energy education to help eligible low-income households conserve energy, reduce energy costs and improve their health, comfort, and safety. The Energy Savings Assistance Common Area Measures (ESA CAM) program provides no-cost energy efficiency measures for deed restricted multifamily properties with a majority of eligible low-income tenant households. The IOUs also provide one ratepayer-funded energy assistance program for qualifying low-income customers meeting the income range from 200 percent of federal poverty guidelines plus $1 to at or below 250 percent. The Family Electric Rate Assistance (FERA) program provides families of three or more, whose household income slightly exceeds the CARE allowances, with an 18 percent discount on their electricity bill.

California Alternate Rates for Energy (CARE)

The CARE program is a low-income energy rate assistance program that provides a discount on energy rates to qualifying low-income households. CARE is funded by non-exempt customers (exempt customers include CARE and FERA customers) as part of a statutory "public purpose program surcharge" that appears on monthly utility bills.

The program was established in 1989 by California Public Utilities Code Sections 739.1 and 739.2, authorizing a 15 percent rate discount for qualifying low-income customers off their energy bills. In 2001, the minimum CARE rate discount was increased from 15 percent to 20 percent by CPUC D.01-06-010. However, due to a number of factors on how rate increases and new charges were allocated to customers, the effective discounts grew to over 40 percent for some CARE customers.

In October 2013, AB 327 was passed requiring the IOUs to restructure the CARE discount rates and to set an effective electric rate discount between 30-35 percent. In 2020, PG&E's CARE effective electric discount was 34.8 percent, SCE's was 32.5 percent, and SDG&E's was 35 percent.[60] In compliance with AB 327 and D.15-07-001, the effective discounts have been reduced to 35 percent for PG&E and SDG&E, and will remain at 32.5 percent for SCE. These reductions have occurred gradually to prevent rate shock.

As economic hardships for California residents have increased over the course of the COVID-19 pandemic, participation in CARE has increased with approximately one million new customer accounts added between March and December 2020. In 2020, the program provided approximately $1.6 billion in annual subsidies and served

[60] Effective CARE rates are available in IOU Tariff reporting.

approximately 5.1 million low income households statewide.[61] A higher CARE subsidy does not result in a higher revenue requirement for the utility, but it does increase the rates that non-CARE customers pay.

PG&E's CARE subsidy in 2020 was approximately $788 million, compared to $515 million for SCE, $140 million for SDG&E, and $151 million for SoCalGas (see **Table 5.3**).

Table 5.3 2020 CARE Program Costs[62]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$657,824,476	$11,896,420	$669,720,896
	Gas	$129,698,403	$2,974,105	$132,672,508
SCE	Electric	$514,642,207	$6,919,983	$521,562,190
SDG&E	Electric	$123,202,068	$4,825,364	$128,027,432
	Gas	$16,412,232	$612,931	$17,025,163
SoCalGas	Gas	$150,624,652	$7,875,283	$158,499,935
Total		**$1,592,404,038**	**$35,104,086**	**$1,627,508,124**

Energy Savings Assistance Program (ESA)[63]

The ESA program provides no-cost home weatherization services, energy efficiency measures (including water-energy saving measures), and energy education to help eligible low-income households conserve energy, reduce energy costs and improve their health, comfort, and safety. The ESA program also has a multifamily whole building program, known as ESA Common Area Measures or ESA CAM, providing energy efficiency measures for deed restricted properties with a majority of low-income households. Program funding comes from the statutory "public purpose program surcharge" that appears on monthly utility bills.

The program's original objective was to promote equity and relieve low-income customers of the burden of rising energy prices. The program has evolved into a resource program that achieves energy savings while improving quality of life for low-income customers.

The CPUC initiated the first energy efficiency programs for low-income customers in the early 1980's. In 1990, the California legislature adopted and codified the ESA program in P.U. Code Section 2790(a) requiring the electrical and gas corporations to perform home weatherization services for low-income customers in their service territory, taking into consideration both the cost-effectiveness of the services and the policy of reducing hardships for low-income households. In 2007, the CPUC adopted a programmatic initiative in D.07-12-051 to provide all eligible customers the opportunity to participate in

[61] Source: 2020 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.14-11-007.
[62] Source: 2020 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.14-11-007.
[63] Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

the ESA program and to offer participants with cost- effective energy efficiency measures in their residences by 2020. P.U. Code Section 382(e) codified this goal so that by the end of 2020, 100 percent of all eligible and willing low-income customers would have the opportunity to participate in the ESA program.

CPUC D.17-12-009, which modifies D.16-11-022, provides direction for the current ESA program cycle from 2017 to 2020. To better serve the needs of low-income multifamily households, the CPUC authorized the treatment of communal areas for qualified deed-restricted multifamily properties within the ESA CAM program. The initial funding of $80 million came from previously unspent ESA funds. The ESA CAM goal is to decrease operating costs for property owners to preserve rent affordability and increase tenants' health, comfort, and safety. In 2020, the ESA CAM program served 117 properties which together contain over 6,713 units and achieved annual energy savings of 2.27 GWh and 0.05 MMtherms.[64]

Customers enroll in the ESA program through various channels including leads from CARE program participants, door-to-door neighborhood canvasing, direct mail, email, community-based organizations, categorical enrollment, online, and community events. Marketing materials are available in multiple languages. ESA is an income verified program; however, customers can enroll automatically if already participating in another financial assistance programs with similar criteria. As a result of the COVID-19 pandemic, which impacted workforce availability and customer willingness to participate in the program, the 2020 goal of treating all eligible and willing customers was not met. ESA will continue to target high energy usage and hard to reach customers not yet enrolled.

Table 5.4 shows the 2020 ESA program costs. In 2020, ESA served approximately 236,034 households (eight percent received energy education only), achieved 87 GWh and 0.55 MMtherms of annual energy savings.[65]

[64] Source: 2020 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.14-11-007. Final property, unit, and energy savings numbers will be available in IOU Annual Reports for Program Year 2020 on May 1, 2021.

[65] The number of households treated was reduced by 10% as a placeholder to account for households treated in shared IOU-territories. Final household treatment numbers will be available in IOU Annual Reports for Program Year 2020 on May 1, 2021.

Table 5.4: 2020 ESA Program Costs[66]

Utility	Operations	ESA Year-To-Date Expenses 2020	ESA CAM Year-To-Date Expenses 2020*
PG&E	Electric and Gas	$139,037,393	$6,145,908
SCE	Electric	$42,096,152	$241,501
SDG&E	Electric and Gas	$14,045,044	$1,016,159
SoCalGas	Gas	$94,623,418	$879,268
Total		**$289,802,007**	**$8,282,835**

*ESA CAM is not a part of the investor-owned utilities' total revenue requirement as it is funded by previously unspent ESA Funds by D.16-11-022, modified by D.17-12-009.

Family Electric Rate Assistance (FERA)

The FERA program is a low-income electric rate assistance program that provides a discount on electric rates to qualifying low-income households with three or more individuals. FERA is funded by non-exempt customers (exempt customers include CARE and FERA customers) as part of a statutory "public purpose program surcharge" that appears on monthly utility bills. The FERA program was designed to assist large families that are ineligible for the California Alternate Rates for Energy (CARE) rate because their income levels are slightly above the CARE program limits.

The income limits of the FERA program range from 200 percent plus $1 to 250 percent of the Federal Poverty Guidelines. Public Utilities Code Section 739.1(f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based upon their level of income and economic need.

The FERA program was established in 2004 by CPUC D.04-02-057 as the Lower Middle Income Large Household program. In D.05-10-044, the lower income limits of the FERA program were raised to 200 percent plus $1 of the Federal Poverty Guideline levels, which correspond to the upper limits of the CARE program. In compliance with Senate Bill 1135 (Bradford, 2018) and California Public Utilities Code §739.12, the FERA program discount increased from 12 percent to 18 percent effective January 1, 2019.

Similar to the increased CARE participation as a result of the COVID-19 pandemic, participation in FERA has increased approximately 45 percent, with 24,000 new customer accounts added between March and December 2020.[67]

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[66] Source: 2020 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.14-11-007.

[67] Source: Energy Division Data Request. Final FERA participation data for 2020 will be available in IOU Annual Reports for Program Year 2020 on May 1, 2021.

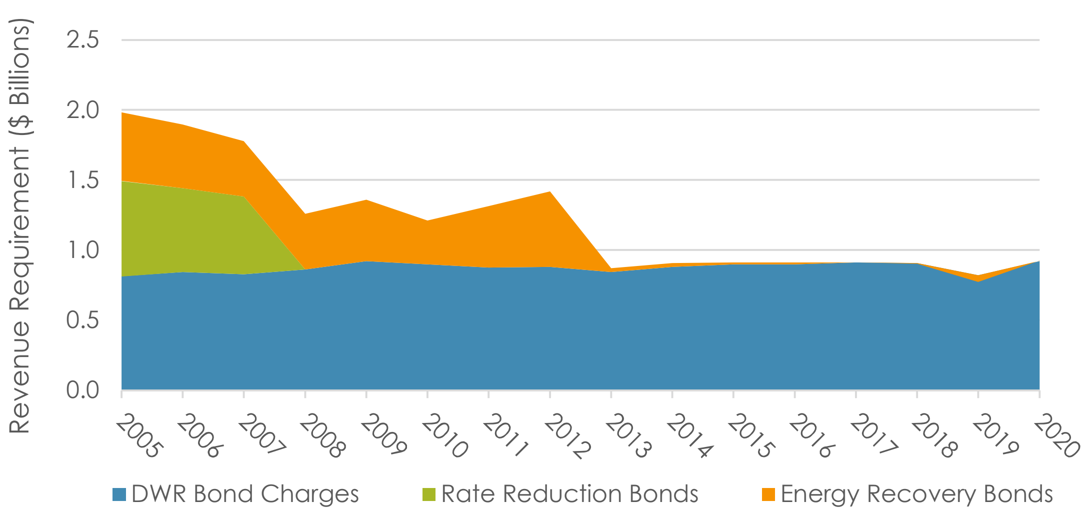
PG&E's FERA subsidy in 2019 was approximately $6.86 million, compared to $8.95 million for SCE, and $2.24 million for SDG&E. FERA information is reported annually and information on customer subsidies for 2020 will be reported in May 2021.[68]

[68] Source: 2019 Investor-Owned Utility ESA CARE FERA Annual Reports, posted to Docket A.14-11-007 on May 1, 2020.

VI. Bonds, Regulatory Fees, and Legislative Program Costs

During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. Since the energy crisis, these bond costs have decreased from a peak of approximately $2 billion in 2005 to $926 million in 2020, as illustrated in **Figure 6.1**.

Figure 6.1: Trends in Bond Expenses ($ Billions)



Rate Reduction Bonds were issued in 1998 and paid back in full in 2007. AB 1890, the legislation that established the terms of energy restructuring, authorized these bonds to provide an immediate reduction in electric rates. Among other things, the legislation froze electric rates at June 1996 levels and reduced rates for residential and small commercial customers by 10 percent.

DWR bonds were issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis. As of September 30, 2020, enough funds were collected from ratepayers to retire the DWR bonds, and consequently the DWR bond charge expired.

On October 1, 2020, pursuant to AB 1054 (2019) and CPUC Decision 19-10-056, the Wildfire Fund Non-Bypassable Charge (NBC) was implemented.[69] The 2020 Wildfire Fund NBC was equivalent to the expired DWR bond charge, resulting in no bill impact

[69] CPUC D.19-10-056, October 24, 2019, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M318/K549/318549782.pdf.

to customers. The Wildfire Fund NBC supports the participation of large electrical utilities in the AB 1054 Wildfire Fund.

Regulatory Asset / Energy Recovery Bonds: As part of the CPUC and PG&E bankruptcy settlement agreement reached after PG&E's first move into bankruptcy protection in 2001, the utility was authorized to recover $2.2 billion as a Regulatory Asset. This was a separate and additional part of PG&E's rate base. The Energy Recovery Bonds were issued by PG&E in 2003 to reduce the financing cost of the Regulatory Asset to ratepayers.

Table 6.1 shows the bond expenses component of the 2020 revenue requirement for each of the electric IOUs.

Table 6.1: 2020 Bond Expenses ($000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges[70]	427,327	428,069	66,926	922,322
Rate Reduction Bonds	0	0	0	0
Energy Recovery Bonds	3,669	0	0	3,669
Total	**430,996**	**428,069**	**66,926**	**925,991**

Fees and Incentives

Fees include a variety of charges levied by federal, state, and local governments. For example, the CPUC fee reimburses the state for the cost of regulating the utilities. Incentives offer a financial inducement for utilities to achieve certain policy goals that may not be effectively accomplished only through regulatory directives. **Table 6.2** shows the 2020 revenue requirement for regulatory fees. In total, this entire category of expenses accounted for roughly five percent of the 2020 revenue requirement. Some fees are included in the other revenue components. Only nuclear decommissioning costs are recovered separately through the Nuclear Decommissioning Adjustment Mechanism.

[70] The DWR Bond Charges are based on the electric revenue requirement in effect on 5/1/2020 (PG&E), 4/13/2020 (SCE), and 1/1/2020 (SDG&E), and may not reflect the changes from the Wildfire Fund Non-Bypassable Charge which was issued on October 1, 2020.

Table 6.2: 2020 Regulatory Fees ($000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC Reimbursement Fee*	47,117	46,584	0	93,701
Franchise Fee & Uncollectible Surcharge**	0	0	3,181	3,181
Catastrophic Events Memo Account***	301,787	51,626	0	353,412
Hazardous Substance Mechanism	29,836	0	164	30,000
Nuclear Decommissioning****	89,909	(44,180)	(12)	45,716
Spent Nuclear Fuel	0	4,333	1,060	5,393
Major Emergency Balancing Account*****	60,943	0	0	60,943
Total	**529,591**	**58,362**	**4,393**	**592,346**

* SDG&E did not include the CPUC fee in the revenue requirements reported here; however, SDG&E did include the CPUC fees in revenue requirements reported for the Legislative Program Costs section below (see Table 6.3). The 2020 electric CPUC reimbursement fees for PG&E, SCE, and SDG&E were $0.00130/kWh.
** Not reported elsewhere.
*** SDG&E funds recorded in CEMA were not authorized to be collected in 2020.
**** Includes Nuclear Decommission franchise fees and uncollectible expense as applicable.
***** For SCE and SDG&E, forecasts for emergency preparedness and response are approved as part of the GRC budget and not in a segregated balancing account.

Definition of Fees

- **CPUC Reimbursement Fee:** This is the annual fee to be paid by utilities to fund their regulation by the CPUC (California Public Utilities (PU) Code Section 401-443). The surcharge to recover the cost of that fee is ordered by the CPUC under authority granted by PU Code Section 433.
- **Franchise Fees:** Fees paid by a privately-owned utility to cities and counties for the right to use or occupy public streets and roads, and for permission to provide service in their jurisdictions. These fees are then redistributed to the cities and counties. In some cases, these fees are included in other cost categories and not separately determined in this report, as appears to be the case with PG&E.[71]
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected.
- **Catastrophic Events Memorandum Account (CEMA)**: An account established to enable a utility to recover the costs associated with the restoration of service and utility facilities affected by a catastrophic event (e.g., an earthquake) or state of emergency declared by federal or state authorities.
- **Hazardous Substance Mechanism:** An account established to allow certain costs of investigating and remediating hazardous waste sites identified by the utilities.

[71] PG&E reported $0 for franchise fees in 2020 and in several other year's past, suggesting that they may have been reported in other cost categories after recovery in surcharges, and not recorded here.

- **Nuclear Decommissioning:** Nuclear decommissioning funds are established for the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Spent nuclear fuel is shown as a separate item.
- **Major Emergency Balancing Account:** Specific to PG&E, the MEBA recovers actual costs resulting from responding to major emergencies and catastrophic events not eligible for recovery through the CEMA. In some cases, costs relating to major emergencies that are found by the CPUC not to be eligible for recovery through the CEMA process may be recoverable through the MEBA.
- **Wildfire Mitigation Plan Memorandum Account:** In 2019, pursuant to SB 901 (Dodd, 2018), each electric utility opened an account to track its costs incurred to implement its annual wildfire mitigation plan and seek recovery at a later date. With the exception of SDG&E, the utilities (PG&E[72] and SCE[73]) have submitted applications to recover the costs recorded in this account.
- **Fire Risk Mitigation Memorandum Account:** In 2019, pursuant to SB 901 (Dodd, 2018), each electric utility was allowed to establish an account to enable it to track its costs incurred for fire risk mitigation that are not otherwise covered in the electric revenue requirement, and seek recovery at a later date. With the exception of SDG&E, the utilities (PG&E[74] and SCE[75]) have submitted applications to recover the costs recorded in this account.

Legislative Program Costs

Various electric programs, operated by the IOUs, are mandated by the State of California. Most programs aim to provide California with clean energy, while some programs provide cost shifts or subsidies to various customer groups. Some bonds and regulatory fees may also be mandated by the State. **Table 6.3** shows the 2020 electric revenue requirement for the legislative mandates.

[72] In CPUC D.20-10-026, PG&E was authorized to recover partial revenue for its Wildfire Mitigation Plan Memorandum Account from December 2020 through April 2022.

[73] SCE is seeking recovery of the Wildfire Mitigation Plan Memorandum Account costs in its Test Year 2021 General Rate Case application.

[74] In CPUC D.20-10-026, PG&E was authorized to recover partial revenue for its Fire Risk Mitigation Memorandum Account from December 2020 through April 2022.

[75] SCE is seeking recovery of the Fire Risk Mitigation Memorandum Account costs in its Test Year 2021 General Rate Case application.

Table 6.3: 2020 California Mandated Programs Revenue Requirement ($000)

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Aliso Canyon Energy Storage	AB 2514	0	11,925	0	**11,925**
California Energy Systems for 21st Century	SB 96	0	388	0	**388**
California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	SB 1, AB 217, AB 2723	7,955	0	0	**7,955**
CPUC Fee	Public Utilities Code § 431-432	47,117	46,536	13,016	**106,669**
Demand Response [76]	SB 1414, AB 793	70,717	43,072	15,264	**129,053**
Department of Water Resources Bond	AB 1X	427,327	422,669	88,135	**938,131**
Disadvantaged Communities - Single-Family Affordable Solar Homes, Green-Tariff, Community Solar Green Tariff	AB 327	0	9,085	3,139	**12,224**
Electric Program Investment Charge/New Solar Homes Partnership Program	Public Utilities Code § 399.8, AB 1890, SB 1, AB X1 15	97,834	76,900	16,280	**191,014**
Energy Efficiency	SB 350, AB 1330, AB 802, AB 32, AB 1890	52,683	57,236	71,388	**181,306**
Energy Savings Assistance Program/California Alternate Rates for Energy Program Administrative Expense	Public Utilities Code § 2790, § 382, AB 327, AB 2857, SB 580, AB 2140	163,028	72,461	137,257	**372,747**
Family Electric Rate Assistance[77]	SB 987, SB 1135	0	0	2,825	**2,825**
Green Tariff Shared Renewables	SB 43	10,249	6,084	0	**16,333**
Greenhouse Gas Cost[78]	AB 32	77,137	251,256	52,130	**380,523**
Greenhouse Gas Revenue Return	AB 32	(433,946)	(380,489)	(88,670)	**(903,105)**
Hazardous Substance Memorandum Account	AB X1 6	29,836	3,831	170	**33,837**

[76] Demand Response includes Demand Response Auction Mechanism and IDSM, as applicable.
[77] Family Electric Rate Assistance includes administrative expenses, as applicable.
[78] PG&E's Greenhouse Gas Cost is presented as a five-year average.

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Mobile Home Park Program	Public Utilities Code § 2791-2799	24,825	25,634	8,196	**58,655**
Net Energy Metering[79]	AB 1070	479	0	0	**479**
Officer Compensation	SB 901	(2,413)	0	(1,770)	**(4,183)**
Renewable Portfolio Standard[80]	SB 1078, SB 350, SB 100	2,142,097	2,348,968	629,618	**5,120,683**
San Joaquin Valley Disadvantaged Communities Pilot and Data Gathering	AB 2672	13,315	10,248	0	**23,563**
Self-Generation Incentive Program	AB 970, SB 700, AB 1144	59,851	56,637	0	**116,488**
Smart Grid	AB 32, SB 17	15	0	0	**15**
Solar on Multifamily Affordable Housing	AB 693	51,442	73,282	11,237	**135,961**
Statewide Marketing Program	AB 793	10,415	8,078	0	**18,493**
Total Rate Adjustment Component	AB 1X	0	0	60,000	**60,000**
Transportation Electrification Programs[81]	SB 350, AB 1082, AB 1083, AB 628	22,671	13,618	7,843	**44,132**
Tree Mortality Non-Bypassable Charge	SB 859	99,516	49,612	21,355	**170,483**
Total		**2,972,150**	**3,207,030**	**1,047,414**	**7,226,593**

[79] Net Energy Metering includes solar system contracts and disclosures, as applicable.

[80] RPS revenue requirements do not distinguish the above-market portion. PG&E's RPS value is presented as a five-year average.

[81] Transportation Electrification includes pilots, as applicable.

VII. Natural Gas Utility Ratepayer Costs

The CPUC determines the reasonableness of natural gas utility operational costs, gas cost allocation among customer classes, and gas rate design for PG&E, SDG&E, and SoCalGas.

Natural gas utility costs may be categorized into the following three main components: 1) core procurement costs, 2) costs of operating the natural gas transportation system and providing customer services, and 3) costs associated with gas public purpose programs (PPP).

Unlike its process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Utilities procure gas supplies for core gas customers (primarily residential and small commercial) only. Utilities' gas procurement is subject to a sharing incentive under which utilities receive a reward if they procure gas at costs below certain benchmarks and incur a penalty if procured at costs above the benchmarks. The mechanism provides utilities with a financial incentive to purchase gas for core ratepayers at costs that are beneficial to the IOU, with part of savings being shared with ratepayers. Procurement costs shown in this report pertain to these core customers. Large volume noncore customers, such as industrial or electric generation, procure their own gas supplies and, therefore, procurement costs of their gas usage are not included herein. Core gas procurement costs are recovered in utility gas procurement rates, which are adjusted monthly. The commodity gas price is the cost component with the greatest variability. Monthly changes in gas commodity prices on customer bills provide consumers with immediate price signals that they can use to adjust their gas usage. The tables below show costs for 2020 and a comparison of 2020 to prior years.

Table 7.1 shows the 2020 natural gas revenue requirement by components.

Table 7.1: 2020 Gas Revenue Requirement by Key Components ($000)

	PG&E	SDG&E	SoCalGas	Total
Core Procurement	770,337	128,346	923,497	1,822,180
Transportation	3,531,809	614,121	3,723,109	7,869,039
Public Purpose Programs	182,489	29,811	363,300	575,600
TOTAL	**4,484,635**	**772,278**	**5,009,906**	**10,266,819**

Table 7.2 shows historical revenue requirement for 2014-2020 for the key components.

Table 7.2: Historical Gas Utility Revenue Requirement ($000) (2014-2020)

	2014	2015	2016	2017	2018	2019	2020
Core Procurement	3,055,256[82]	2,380,796	2,053,769	2,465,182	2,067,169	2,226,842	1,822,180
Transportation	4,788,140	5,390,916	6,753,286	6,275,397	6,458,407	7,418,647	7,869,039
Public Purpose Programs	581,915	670,067	639,808	647,260	604,622	650,968	575,600
Total	**8,425,311**	**8,441,779**	**9,446,863**	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**

As **Table 7.2** shows, the 2020 total natural gas utility costs decreased by 0.3 percent from 2019 compared to the 12.8 percent increase for 2018-2019. Compared to 2019, PG&E's total natural gas utility costs in 2020 decreased by 2.2 percent, SoCalGas' costs decreased by 0.7 percent, and SDG&E's costs increased by 15.9 percent. (See **Table 7.3**).

Table 7.3 shows the trends in natural gas revenue requirement.

Table 7.3: Historical Revenue Requirement ($000)

	2014	2015	2016	2017	2018	2019	2020
PG&E	3,711,209	4,071,409	4,789,682	4,610,816	4,470,985	4,587,569	4,484,635
SoCalGas	4,162,340	3,826,574	4,095,158	4,191,353	4,113,388	5,042,690	5,009,906
SDG&E	551,762	543,796	562,023	585,670	545,825	666,198	772,278
Total	**8,425,311**	**8,441,779**	**9,446,863**	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**

Changes in the components of revenue requirement are summarized below and discussed in more detail in their respective sections.

Compared to 2018, PG&E's revenue requirement in 2019 had increased by 2.6 percent. For SoCalGas and SDG&E, revenue requirement in 2019 had increased by 22.6 percent and 23.5 percent, respectively. In the case of SoCalGas, increased distribution revenue requirement and GHG costs (included for the first time in 2019) accounted for 83% of the total increase. For SDG&E, increased distribution revenue requirement accounted for 63.6 percent of the total increase.

Gas utility transportation and distribution costs, a subset of total costs, increased by 6.1 percent from 2019 to 2020.

Another subset of total costs is core procurement. In 2020, overall core procurement decreased for each of the three gas IOUs compared to 2019, with an aggregate decrease of 18.17 percent.

[82] In previous years' reports, the Revenue Requirement for Core Procurement ($000) for 2014 was incorrectly reported as $3,553,256. This was corrected in Table 7.2 for the 2019 reporting period.

A third component of total costs, natural gas PPP costs, decreased by 11.6 percent from 2019 to 2020. These are the expenditures for CARE and low-income energy-efficiency programs, both of which are designed to subsidize low-income households' utility bills.

Figure 7.1 and **Figure 7.2** show the trends in natural gas utility revenue requirements.

Figure 7.1: Historical Trends in Gas Utility Revenue Requirement ($ Billions)

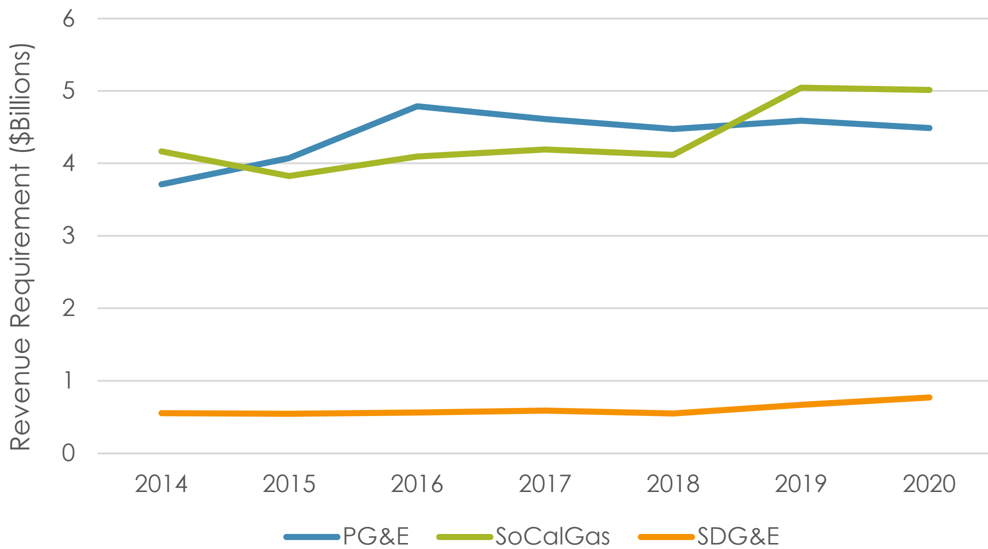
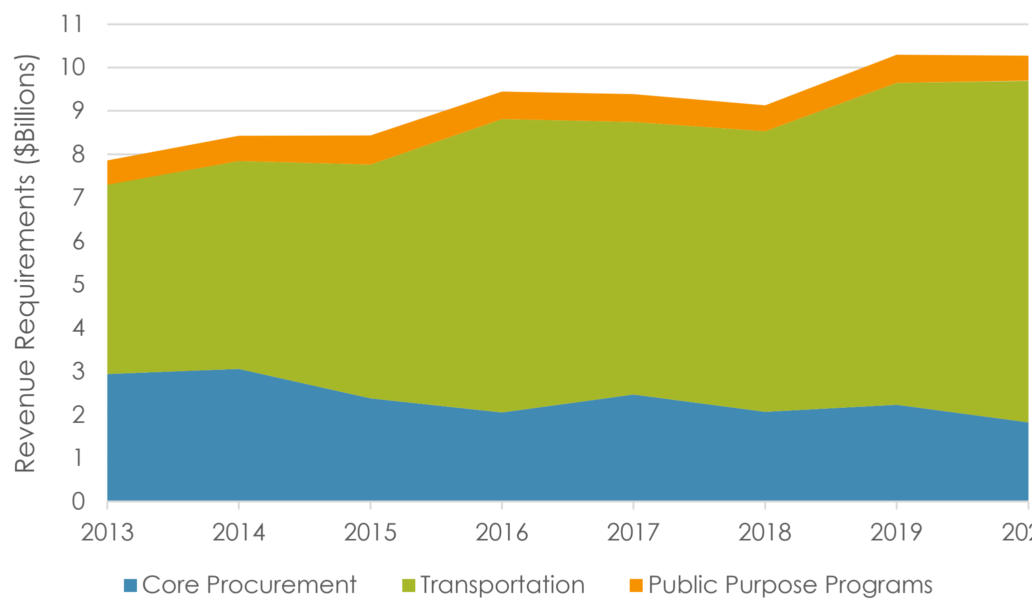


Figure 7.2: Historical Trends in Gas Utility Revenue Requirement Components ($ Billions)



Core Gas Procurement

The gas utilities recover the actual cost of procurement of natural gas for core customers through a rate component called the gas procurement rate. The gas procurement rate changes every month to reflect the most current commodity prices for natural gas.

Core gas customers in California have the option to choose between utility gas procurement service and gas procurement service from other entities called Core Transport Agents (CTAs). Even with CTAs, over 80 percent of core gas customers still receive gas procurement service from the utility. In contrast, almost all larger, noncore natural gas consumers--industrial customers or electric generators--procure their own natural gas supplies using non-utility suppliers. The procurement costs shown in this section reflect only the utilities' costs of providing procurement service to core customers.

Core procurement costs include the various costs associated with procuring natural gas supplies for a utility's core gas customers, such as the cost of the commodity, interstate pipeline capacity costs, hedging costs, and other costs. However, the major component of core procurement costs is the cost of the commodity itself.

Due to a significant decrease in the price of natural gas since mid-2008, the state's natural gas utilities' procurement costs have decreased by 40 percent from 2014 to 2020.

In 2020, procurement costs aggregated across the IOUs decreased by 18 percent (as discussed later). However, a polar vortex event, which occurred in the South and the Midwest in February 2021 may lead to a rise in 2021 gas procurement costs. California saw gas prices spike as a result of the increased demand in states hit by the cold weather, a decreased production due to freeze-offs in Texas and Oklahoma basins, and the marketers' movement of gas to highest-priced markets.

Neither the CPUC nor FERC regulates the wholesale price of natural gas.

Table 7.4 and **Figure 7.3** show the historical revenue requirement for natural gas core procurement.

Table 7.4: Historical Core Procurement Revenue Requirement ($000)

	2014	2015	2016	2017	2018	2019	2020
PG&E	1,378,948	1,289,757	1,020,570	1,158,601	879,270	935,782	770,337
SoCalGas	1,481,448	951,033	912,847	1,154,731	1,048,393	1,134,044	923,497
SDG&E	194,860	131,006	120,352	151,850	139,506	157,016	128,346
Total	**3,055,256**	**2,371,796**	**2,053,769**	**2,465,182**	**2,067,169**	**2,226,842**	**1,822,180**

Figure 7.3: Historical Natural Gas Core Procurement Revenue Requirement ($ Billions)

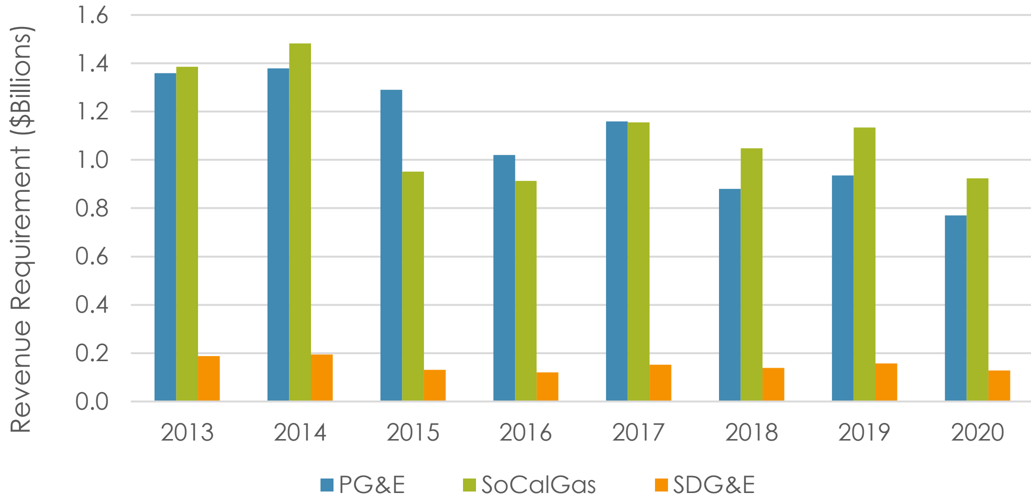


Table 7.5 shows the change in revenue requirement for core procurement.

Table 7.5: Percentage Change in Revenue Requirement for Core Procurement (2016-2020)

	2016-17	2017-18	2018-19	2019-20
PG&E	14%	(24%)	6%	(18%)
SDG&E	26%	(8%)	13%	(19%)
SoCalGas	26%	(9%)	8%	(18%)
Total	**20.03%**	**(16.15%)**	**7.72%**	**(18.17%)**

For 2016-17, **Table 7.5** shows large increases in the overall natural gas core procurement costs for the three major utilities. Procurement costs increased by 14 percent for PG&E. The increase in procurement costs was much larger at 26 percent for both SoCalGas and SDG&E, likely in response to system issues with storage and pipeline capacity.

For 2018, overall core gas procurement costs decreased from 2017. This decrease was reflected in the large reduction in core procurement costs (24 percent) for PG&E in 2017-2018. Procurement costs decreased by smaller margins for SDG&E (8 percent) and SoCalGas (9 percent) due to ongoing constraints on the SoCalGas system.

For 2019 compared to 2018, overall core procurement increased for each of the three IOUs. The 7.72 percent increase in 2019 was due to the cold winter and IOUs' spot market purchases. In 2019, core gas procurement costs accounted for about 22 percent of the total utility costs.

For 2020 compared to 2019, overall core procurement decreased for each of the three IOUs, with an aggregate reduction of 18.17 percent. For PG&E, core procurement decreased by 18 percent. In March 2020, the Gas Cost Allocation Proceeding was implemented, which adopted an updated sales forecast used to calculate the illustrative Revenue Requirement for the Core Gas Supply, a major component of PG&E's Core Gas Procurement. The sales forecast was 19 percent lower compared to the previous years. The last time the sales forecast was updated was 2010.

In 2020, compared to 2019, for SoCalGas, core procurement decreased by 18 percent and for SDG&E, core procurement decreased by 19 percent. For SoCalGas, the unweighted commodity price decreased about 11 percent, and core consumption in 2020 decreased by about 4 percent, mainly due to COVID-19 and warmer weather in 2020. The pattern for SDG&E was similar.

In 2020, core gas procurement costs accounted for about 17.7 percent of the total utility costs.

Gas Transmission, Distribution, and Storage Costs

The CPUC authorizes natural gas distribution utilities' revenue requirements for operating their extensive natural gas transmission, distribution, and storage systems and for providing various customer services. These costs have steadily increased in recent years. The bulk of these revenue requirements are determined by the CPUC in the utilities' rate cases.

Table 7.6 shows historical revenue requirement for transportation for 2014-2020. Increases in total authorized revenue requirement for transmission, distribution, storage, and customer services, combined under the "transportation" category, have increased by 46 percent from 2015 to 2020. Such costs increased by 41 percent, 48 percent, and 62 percent for PG&E, SoCalGas, and SDG&E, respectively, from 2015 to 2020. In addition, with the recent emphasis on safety and replacement of aging infrastructure, the CPUC has authorized increased revenue requirement for all three major gas utilities with respect to transmission and distribution.

Table 7.6: Historical Transportation Revenue Requirement ($000)

	2014	2015	2016	2017	2018	2019	2020
PG&E	2,076,507	2,500,926	3,494,033	3,184,277	3,343,689	3,389,751	3,531,809
SoCalGas	2,392,986	2,511,953	2,850,105	2,693,301	2,741,585	3,550,769	3,723,109
SDG&E	318,647	378,037	409,148	397,819	373,133	478,127	614,121
Total	**4,788,140**	**5,390,916**	**6,753,286**	**6,275,397**	**6,458,407**	**7,418,647**	**7,869,039**

Table 7.7 shows the change in revenue requirement for transportation.

Table 7.7: Percentage Change in Revenue Requirement for Transportation (2017-2020)

	2016-17	2017-18	2018-19	2019-20
PG&E	(9%)	5%	1%	4%
SDG&E	(3%)	(6%)	28%	28%
SoCalGas	(6%)	2%	30%	5%
Total	**(7.08%)**	**2.92%**	**14.87%**	**6.07%**

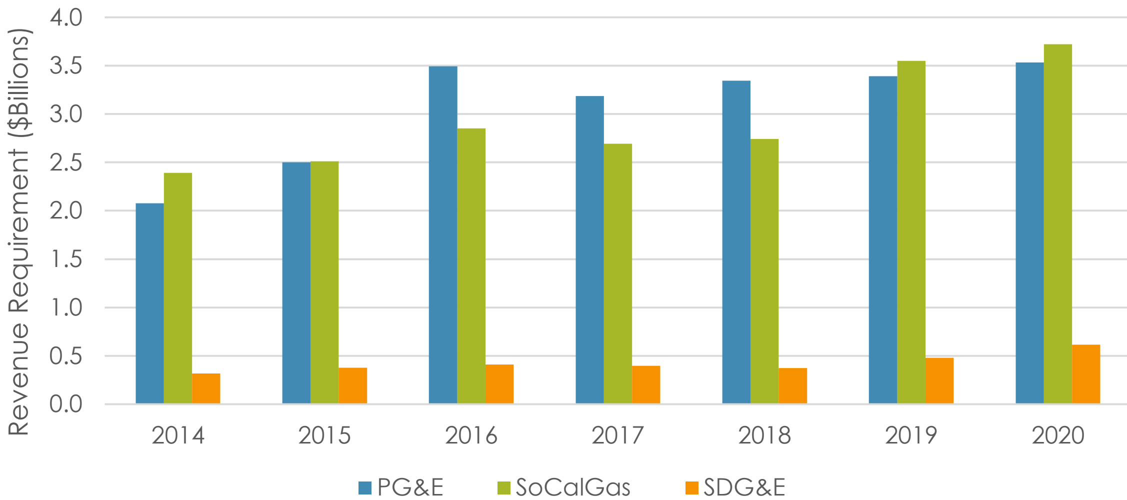
In **Table 7.7**, comparing 2020 to 2019, gas transportation costs increased by 6.07 percent and represented 76.6 percent of total utility gas costs. The increases in Transportation costs for PG&E, SoCalGas, and SDG&E were 4 percent, 5 percent, and 28 percent, respectively.

A major factor in the increase in 2019 total transportation costs was that for the first time for SoCalGas and SDG&E, Greenhouse Gas (GHG) Program Costs and Proceeds (see further discussion below) were included in the transportation costs.

For 2020 compared to 2019, the increase in aggregate Transportation revenue requirement of the three IOUs is predominantly accounted for by an increase in “Other Balancing Account Balances” ($328 million), and in Distribution and Distribution Integrity Management Program (DIMP) taken together ($208 million). These are offset by smaller decreases in several programs that are part of the Transportation revenue requirement.

Figure 7.4 shows the historical revenue requirement for transmission, distribution, and storage.

Figure 7.4: Historical Natural Gas Transportation Revenue Requirement ($ Billions)



Legislative Program Costs

Several natural gas programs operated by the IOUs are under State mandates, apart from those under CPUC mandates. Among these, two large components are: (1) Greenhouse Gas Costs and Allowance Proceeds; and (2) Gas Public Purpose Program (PPP) Costs, discussed in detail below. Information on the applicable State-Mandates (including PUC Sections) for covered programs is included in Appendix B for Gas Costs.

Table 7.8 shows the 2020 revenue requirement for State-Mandated programs.

Table 7.8: 2020 State Mandated Programs Revenue Requirement ($000)

	PG&E	SDG&E	SoCalGas	Total
Self Generation Incentive Program (SGIP)	12,990	2,060	16,271	**31,321**
California Solar Initiative (CSI)	8,477	1,401	22,759	**32,637**
CPUC Fee[83]	29,100	N/A	N/A	**29,100**
Franchise Fee Surcharge (G-SUR)[84]	6,099	0	19,568	**25,667**
Greenhouse Gas (GHG) Program	35,018	31,950	249,788	**316,756**
Energy Efficiency (EE) Programs	70,279	812	93,255	**164,346**
Low Income Energy Efficiency (LIFE)	(9,378)	11,572	134,474	**136,668**
Public Interest RD&D and State Board of Equalization (BOE) Administrative Fees	10,172	3,053	11,338	**24,563**
California Alternate Rates for Energy (CARE) Program	111,416	14,374	124,233	**250,023**
Total	**274,173**	**65,222**	**671,686**	**1,011,081**

Greenhouse Gas Compliance Costs and Allowance Proceeds

Since January 1, 2015, natural gas utilities have been covered under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the natural gas utilities must buy compliance instruments - offsets and allowances - and surrender them to the California Air Resources Board (CARB) to account for GHG emissions associated with the combustion or oxidation of fuels they provide to customers in California (less any amount delivered to covered entities that supply their own compliance instruments to CARB). CARB holds quarterly allowance auctions where entities can buy and sell allowances. IOUs can also procure compliance instruments on secondary markets or through contractual arrangements.

CARB allocates some allowances to natural gas utilities on behalf of their ratepayers. The Cap-and-Trade regulation requires the investor-owned natural gas utilities to sell an increasing share of these allowances at CARB's quarterly allowance auctions and use the proceeds for the benefit of ratepayers, starting at 25 percent of their allocated allowances in 2015 and increasing at a rate of 5 percent a year through 2030 (when 100 percent will be sold for ratepayer benefit). For 2020, natural gas utilities were required to sell 50 percent of allocated allowances for ratepayer benefit. The proceeds from the sale of GHG allowances must be used exclusively for ratepayer benefit, consistent with the goals of AB 32 ("The California Global Warming Solutions Act," Nunez, 2006), CARB regulations, and as directed by the CPUC. The CPUC has

[83] SDG&E and SoCalGas did not include the CPUC Fee in the revenue requirement reported here, but they do collect this fee as a separate charge on utility bills. The 2020 gas CPUC reimbursement fees for PG&E, SDG&E, and SoCalGas are $0.00577/therm.

[84] SDG&E did not include the G-SUR amount in the revenue requirement reported here, but SDG&E's 2020 G-SUR amount was $2.919 million, and shown as a CPUC Mandate, CPUC D.19-09-051.

determined the methodologies the utilities should use to return proceeds. D.15-10-032 and D.18-03-17 instructed natural gas utilities to return proceeds to residential ratepayers each April as an on-bill credit, with each residential ratepayer receiving an equal share of their utilities' available proceeds. In addition to customer credits, pursuant to SB 1477, starting in fiscal year 2019, $50 million of allowance proceeds will be used for building decarbonization pilot projects each year through fiscal year 2023.[85]

Beginning in 2015, the natural gas utilities started tracking Cap-and-Trade-related costs and allowance proceeds. However, these costs and credits were not introduced into customer rates until July 1, 2018.[86] PG&E provided the 2018 credit in October 2018 and the 2019 credit in April 2019. SDG&E and SoCalGas distributed their 2018 and 2019 credits together in April 2019. All investor-owned natural gas utilities will distribute the natural gas California Climate Credit annually in April going forward.

In 2020, the natural gas IOUs collectively introduced approximately $516 million in GHG costs into rates and returned approximately $266 million in allowance proceeds to customers (see **Table 7.9**).

Table 7.9: 2020 Greenhouse Gas Costs and Allowance Proceeds[87]

	2020 Natural Gas GHG Revenue Requirement	2020 Natural Gas Proceeds Distributed to Customers
PG&E	$191,368,254	($115,404,207)
SDG&E	$57,123,206	($18,661,550)
SoCalGas	$276,607,638	($131,585,613)
Total	**$516,099,098**	**($265,651,370)**

Gas Public Purpose Program (PPP) Costs

The CPUC also authorizes costs for three main categories of gas PPPs: energy efficiency (EE) and low-income EE, the CARE subsidy, and the gas public interest research and development program administered by the California Energy Commission. Gas PPP costs are determined in various CPUC proceedings associated with the particular type of gas PPP. Gas PPP costs have increased since 2008 but are a relatively small part of total costs.

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[85] Fiscal Year begins July 1. Funds for FY2019 were collected out of 2020 allowance proceeds, alongside FY2020 funding.

[86] D.18-03-07 instructed the natural gas utilities to net compliance costs against proceeds for the 2015-2017 period and either (1) amortize costs over a 12-month period starting in July 2018 if costs exceeded proceeds or (2) distribute the net proceeds in 2018 as a climate credit if proceeds exceeded costs. D.18-03-017 also ordered that 2018 GHG compliance costs be amortized in rates over an 18-month period starting July 2018.

[87] Revenue requirement based on 2020 forecasted amounts; proceeds based on 2020 recorded amounts. Proceeds excludes $69.3 million set aside for the Building Initiative for Low-Emissions Development program and Technology and Equipment for Clean Heating. SDG&E costs include $24.6 million of cost amortization from prior years. SoCalGas costs include $105.2 million of cost amortization from prior years.

Costs authorized by the CPUC in 2020 for natural gas PPPs decreased by 11.6 percent from 2019. Gas PPP costs made up 5.6 percent of total utility costs in 2020. The large decrease in aggregate PPP revenue requirement is largely due to a reduction in PG&E's Energy Savings Assistance (ESA)[88] program component of PPP revenue requirement, and a true-up in 2020 for a large overcollection in 2019.

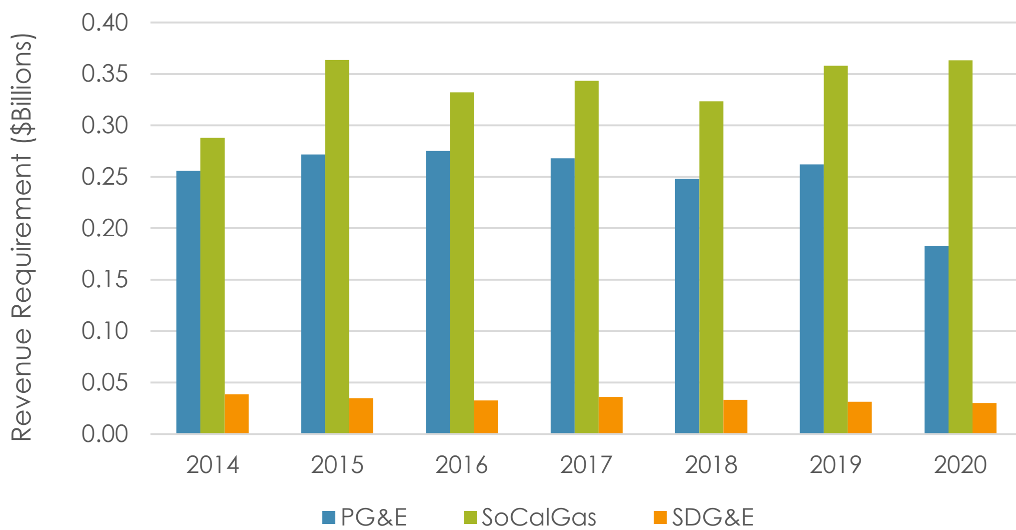
Gas PPP costs are recovered through the gas PPP surcharge on core and non-exempt noncore customers. Only non-CARE customers pay for the CARE subsidy portion of the gas PPP surcharge. The gas PPP surcharges are changed annually through advice letter filings, incorporating the revenue requirements for the gas PPPs adopted in CPUC proceedings.

Table 7.10 and **Figure 7.5** show the historical revenue requirement for public purpose programs.

Table 7.10: Historical Public Purpose Programs Revenue Requirement ($000)

	2014	2015	2016	2017	2018	2019	2020
PG&E	255,754	271,726	275,079	267,938	248,026	262,036	182,489
SoCalGas	287,906	363,588	332,206	343,321	323,410	357,877	363,300
SDG&E	38,255	34,753	32,523	36,001	33,186	31,055	29,811
Total	**581,915**	**670,067**	**639,808**	**647,260**	**604,622**	**650,968**	**575,600**

Figure 7.5: Historical Revenue Requirement for Gas Utility Public Purpose Programs ($ Billions)



[88] Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

Appendix A: Historical Electric Revenue Requirements 2020-2017

2020 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,514,686**	**5,514,150**	**1,507,396**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	183,050	3,124,621	6,701
General Rate Case Revenues		CPUC Decisions	2,238,948	735,315	183,153
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,851,969	Included with Qualifying Facilities	857,111
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,235,381	1,642,236	514,612
Other		CPUC Decisions, Resolutions	5,337	11,978	(54,182)
Transmission Total			**2,469,714**	**949,095**	**559,089**
Reliability Services	FERC Order 459		(36,546)	0	624
Transmission Access Charge	FERC		490,935	45,336	(287,001)
Transmission Owner Rate Case Revenues	FERC		2,015,324	962,976	858,000
Other - FERC Rate Case Revenues	FERC		0	(59,218)	(19,166)
Other			0	0	6,632
Distribution Total			**4,988,079**	**4,777,874**	**1,517,842**
General Rate Case Revenues		CPUC Decisions	4,988,079	4,777,874	1,517,842
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**89,909**	**(39,847)**	**1,048**
Demand Side Management and Customer Programs Total*			**161,861**	**286,496**	**462,716**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	56,637	20,070
California Solar Initiative		CPUC Decisions	7,955	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	74,097	21,483	14,736
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	98,941	46,541	0
Energy Efficiency (non-PUC 399.8)			(62,284)	0	71,388
Electricity Program Investment Charge		CPUC Decisions	97,834	76,900	16,280
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	71,412	65,808	13,145
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	91,616	(8,531)	124,112
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	18,300	(13,920)	52,512
Other		CPUC Decisions, Resolutions	(295,863)	41,578	150,473
Other Regulatory Total*			**439,683**	**98,209**	**8,064**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	301,787	51,626	0
Hazardous Substance Mechanism		CPUC Decisions	29,836	0	164
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	47,117	46,584	0
Other		CPUC Decisions, Resolutions	60,943	0	7,900
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(974)**	**(5,400)**	**(1,100)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**427,327**	**428,069**	**66,926**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**16,840**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**3,669**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**3,181**
Electric Total			**14,093,952**	**12,008,645**	**4,142,002**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2019 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,388,555**	**5,926,553**	**1,668,615**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	181,551	2,719,189	7,566
General Rate Case Revenues		CPUC Decisions	2,156,844	670,615	244,650
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,931,130	Included with Qualifying Facilities	746,366
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,041,266	2,494,399	735,655
Other		CPUC Decisions, Resolutions	77,763	42,350	(65,622)
Transmission Total			**2,206,039**	**1,016,889**	**634,909**
Reliability Services	FERC Order 459		(24,241)	2,977	115
Transmission Access Charge	FERC		500,276	45,336	(265,539)
Transmission Owner Rate Case Revenues	FERC		1,736,739	1,039,554	900,051
Other - FERC Rate Case Revenues	FERC		(6,735)	(70,978)	(7,255)
Other			0	0	7,537
Distribution Total			**5,004,292**	**3,881,203**	**1,296,667**
General Rate Case Revenues		CPUC Decisions	5,004,292	3,881,203	1,296,667
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**79,414**	**(27,773)**	**(590)**
Demand Side Management and Customer Programs Total*			**323,135**	**(38,479)**	**512,218**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	55,998	20,069
California Solar Initiative		CPUC Decisions	7,955	3,840	2,002
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	68,419	37,997	11,838
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	92,009	92,892	0
Energy Efficiency (non-PUC 399.8)			73,624	0	104,038
Electricity Program Investment Charge		CPUC Decisions	89,885	76,095	17,138
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	129,493	63,617	5,829
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	57,758	(1,288)	38,000
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	3,381	(10,615)	123,934
Other		CPUC Decisions, Resolutions	(259,241)	(357,015)	189,369
Other Regulatory Total*			**70,252**	**46,584**	**5,270**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	4,800	0	0
Hazardous Substance Mechanism		CPUC Decisions	39,657	0	270
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	48,009	46,584	0
Other		CPUC Decisions, Resolutions	(22,214)	0	5,000
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(4,057)**	**(5,437)**	**(434)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**376,681**	**366,979**	**77,388**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**(136,983)**	**0**	**12,493**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(46,396)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**705**	**5,165**
Electric Total			**13,260,932**	**11,167,224**	**4,211,701**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2018 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,668,922**	**5,934,570**	**1,822,448**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	182,537	2,594,336	43,088
General Rate Case Revenues		CPUC Decisions	1,981,324	750,267	242,986
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,068,222	Included with Qualifying Facilities	691,131
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,398,617	2,352,938	887,777
Other		CPUC Decisions, Resolutions	38,223	237,030	(42,534)
Transmission Total			**2,146,305**	**1,024,468**	**502,821**
Reliability Services	FERC Order 459		170,611	4,136	734
Transmission Access Charge	FERC		430,524	(26,963)	(304,074)
Transmission Owner Rate Case Revenues	FERC		1,556,910	1,162,882	813,492
Other - FERC Rate Case Revenues	FERC		(11,740)	(115,588)	(13,302)
Other			0	0	5,970
Distribution Total			**4,702,384**	**4,663,722**	**1,299,314**
General Rate Case Revenues		CPUC Decisions	4,702,384	4,663,722	1,299,314
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**22,625**	**4,400**	**(939)**
Demand Side Management and Customer Programs Total*			**328,882**	**181,450**	**566,662**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,849	55,998	0
California Solar Initiative		CPUC Decisions	8,292	6,000	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	41,271	42,854	19,358
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,806	312,268	0
Energy Efficiency (non-PUC 399.8)			251,626	0	112,520
Electricity Program Investment Charge		CPUC Decisions	96,989	69,840	47,060
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	82,946	62,540	16,684
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	38,391	(3,259)	(7,000)
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	(26,720)	18,112	93,832
Other		CPUC Decisions, Resolutions	(344,568)	(382,903)	284,208
Other Regulatory Total*			74,607	0	1,318
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
Hazardous Substance Mechanism		CPUC Decisions	36,183	0	223
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	38,133	0	0
Other		CPUC Decisions, Resolutions	292	0	1,095
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	(1,171)	0	0
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	408,607	406,524	91,076
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	(79,700)	0	29,399
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	(3,773)	0	0
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	0	4,243	6,301
Electric Total			13,267,690	12,219,378	4,318,400

*Recovered in distribution rate component

**Not reported elsewhere.

Appendix A (cont.)

2017 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**6,210,080**	**5,569,248**	**1,814,687**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	97,880	2,485,433	41,886
General Rate Case Revenues		CPUC Decisions	1,948,890	605,317	289,538
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,292,419	Included with Qualifying Facilities	775,090
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,864,807	2,323,409	775,067
Other		CPUC Decisions, Resolutions	6,085	155,090	(66,893)
Transmission Total			**1,936,457**	**1,011,823**	**582,004**
Reliability Services	FERC Order 459		0	14,308	3,077
Transmission Access Charge	FERC		529,280	(83,659)	(171,143)
Transmission Owner Rate Case Revenues	FERC		1,522,521	1,188,758	775,937
Other - FERC Rate Case Revenues	FERC		(115,344)	(107,584)	(32,778)
Other			0	0	6,911
Distribution Total			**4,717,006**	**4,667,759**	**1,284,950**
General Rate Case Revenues		CPUC Decisions	4,717,006	4,667,759	1,284,950
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**125,779**	**1,529**	**(10,001)**
Demand Side Management and Customer Programs Total			**512,273**	**389,980**	**510,162**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,988	27,999	10,035
California Solar Initiative		CPUC Decisions	7,959	8,840	3,560
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	66,521	76,850	15,959
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,865	338,197	0
Energy Efficiency (non-PUC 399.8)			208,767	0	107,199
Electricity Program Investment Charge		CPUC Decisions	89,000	69,840	24,790
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	81,691	62,376	15,168
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	38,211	(15,098)	(24,471)
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	56,446	156,287	96,001
Other		CPUC Decisions, Resolutions	(187,176)	(335,310)	261,920
Other Regulatory Total*			**52,117**	**20,648**	**0**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
Hazardous Substance Mechanism		CPUC Decisions	20,438	0	0
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	35,694	20,648	0
Other		CPUC Decisions, Resolutions	(4,016)	0	0
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(2,516)**	**0**	**0**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**406,896**	**414,068**	**91,076**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**274,363**	**0**	**32,015**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(432)**	**-**	**-**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**4,032**	**4,086**
Electric Total			**14,232,023**	**12,079,088**	**4,308,979**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix B: Historical Natural Gas Revenue Requirements 2020-2017

2020 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**770,337**	**128,346**	**923,497**
Core Gas Supply Portfolio		CPUC Decisions	388,032	128,346	910,691
Other		CPUC Decisions	370,475	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	11,830	0	0
Incentive Mechanism		Report	0	0	12,806
Transportation Total			**3,531,809**	**614,121**	**3,723,109**
Distribution		CPUC Decisions	2,150,472	429,735	2,834,463
Gas Pipeline Integrity Mgmt. (DIMP)				78,785	203,021
PSEP					
SoCalGas Only - SIMP					
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,170,454	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				16,789	66,302
PSEP					
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	2,060	16,271
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	8,477	1,401	22,759
Annual Earning Assessment (AEAP)		CPUC Decisions	2,937	0	304
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	38,678
Haz Substance Mechanism (HSM)		CPUC Decisions	68,836	204	2,647
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	15,793
Core Pricing Flexibility Program		CPUC Decisions	0	0	688
Non-core competitive load growth program		CPUC Decisions	0	0	1,913
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	16,138	47,992	241,218
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,994	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	6,099	2,919	19,568
AB 32 Cap-And-Trade			24,294	2,286	9,696
GHG Program			35,018	31,950	249,788
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**182,489**	**29,811**	**363,300**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	70,279	812	93,255
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	(9,378)	11,572	134,474
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,172	3,053	11,338
Calif Alternate Rates for Energy (CARE) Program			111,416	14,374	124,233
GAS TOTAL			**4,484,635**	**772,278**	**5,009,906**

Appendix B (cont.)

2019 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**935,782**	**157,016**	**1,134,044**
Core Gas Supply Portfolio		CPUC Decisions	506,105	157,016	1,117,245
Other		CPUC Decisions	422,266	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	4,848	0	0
Incentive Mechanism		Report	2,563	0	16,799
Transportation Total			**3,389,751**	**478,127**	**3,550,769**
Distribution		CPUC Decisions	2,085,766	402,360	2,796,303
Gas Pipeline Integrity Mgmt. (DIMP)				43,695	160,234
PSEP					
SoCalGas Only - SIMP					
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,178,640	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				6,361	77,062
PSEP					
Advanced Metering Infrastructure		Report	0	0	21,750
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	1,545	16,270
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	7,358	1,834	25,492
Annual Earning Assessment (AEAP)		CPUC Decisions	612	0	258
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	48,562
Haz Substance Mechanism (HSM)		CPUC Decisions	91,470	580	4,223
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	15,658
Core Pricing Flexibility Program		CPUC Decisions	0	0	1,619
Non-core competitive load growth program		CPUC Decisions	0	0	2,266
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	(76,948)	10,313	43,780
CPUC Fee	PUC Section 431	Resolution M-4816	11,661	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,849	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	7,047	2,521	20,492
AB 32 Cap-And-Trade			25,403	615	9,264
GHG Program			38,903	8,303	307,536
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**262,036**	**31,055**	**357,877**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	64,668	10,996	102,319
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	78,343	6,436	131,837
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,092	1,258	14,136
Calif Alternate Rates for Energy (CARE) Program			107,933	12,365	109,585
GAS TOTAL			**4,587,569**	**666,198**	**5,042,690**

Appendix B (cont.)

2018 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**879,270**	**139,506**	**1,048,393**
Core Gas Supply Portfolio		CPUC Decisions	517,473	139,506	1,037,040
Other		CPUC Decisions	362,041	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	(3,316)	0	0
Incentive Mechanism		Report	3,072	0	11,353
Transportation Total			**3,343,689**	**373,133**	**2,741,585**
Distribution		CPUC Decisions	1,964,824	325,765	2,331,772
Transmission		CPUC Decisions	1,281,236	0	0
Advanced Metering Infrastructure		Report	0	0	31,780
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	2,317	24,405
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	6,722	1,638	13,862
Annual Earning Assessment (AEAP)		CPUC Decisions	182	0	638
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	52,872
Haz Substance Mechanism (HSM)		CPUC Decisions	83,469	520	1,396
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	12,924
Core Pricing Flexibility Program		CPUC Decisions	0	0	784
Non-core competitive load growth program		CPUC Decisions	0	0	1,795
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	10,526	6,261	28,610
CPUC Fee	PUC Section 431	Resolution M-4816	7,837	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	5,102	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	5,842	2,057	22,589
AB 32 Cap-And-Trade			19,677	614	6,461
GHG Program	Sections 95851 (b), and 95852 (c) of Title 17	CPUC Decisions	(54,718)	-	-
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**248,026**	**33,186**	**323,410**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	57,823	11,931	74,527
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	75,742	16,002	129,252
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,840	1,203	13,294
Calif Alternate Rates for Energy (CARE) Program			103,621	4,050	106,337
GAS TOTAL			**4,470,985**	**545,825**	**4,113,388**

Appendix B (cont.)

2017 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			1,158,601	151,850	1,154,731
Core Gas Supply Portfolio		CPUC Decisions	792,973	151,850	1,150,484
Other		CPUC Decisions	354,497	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	5,452	0	0
Incentive Mechanism		Report	5,679	0	4,247
Transportation Total			3,184,277	397,819	2,693,301
Distribution		CPUC Decisions	1,966,317	375,042	2,292,672
Transmission		CPUC Decisions	1,105,365	0	0
Advanced Metering Infrastructure		Report	-	0	79,980
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,989	773	8,135
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	9,998	672	19,643
Annual Earning Assessment (AEAP)		CPUC Decisions	2,308	0	3,375
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	51,662
Haz Substance Mechanism (HSM)		CPUC Decisions	46,826	(2,384)	3,121
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	11,557
Core Pricing Flexibility Program		CPUC Decisions	0	0	1,322
Non-core competitive load growth program		CPUC Decisions	0	0	762
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	16,043	(711)	41,893
CPUC Fee	PUC Section 431	Resolution M-4816	6,562	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	5,172	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	9,067	2,304	18,915
AB 32 Cap-And-Trade			3,630	593	5,679
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	267,938	36,001	343,321
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	71,598	12,943	85,705
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	69,429	11,340	132,249
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,196	1,260	13,002
Calif Alternate Rates for Energy (CARE) Program			115,715	10,458	112,365
GAS TOTAL			**4,610,816**	**585,670**	**4,191,353**